ORAL ARGUMENT NOT SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS, et al., Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al. Respondents.	No. 24-1054 (and consolidated cases)

On Petition for Review of Final Action of the
United States Environmental Protection Agency

STATE RESPONDENT-INTERVENORS' OPPOSITION TO INDUSTRY MOVANT-PETITIONERS' MOTION TO STAY

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GLOSSARY

Act	Clean Air Act
EPA	U.S. Environmental Protection Agency
RIA	EPA, Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Dec. 2023)
Rule	"Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 89 Fed. Reg. 16,820 (Mar. 8, 2024)
Section 111	42 U.S.C. § 7411
TSD	EPA, Background Technical Support Document for the Final New Source Performance Standards and Emission Guidelines (Nov. 2023)

PRELIMINARY STATEMENT

Michigan Oil and Gas Association, Miller Energy Company, and Producer Association Petitioners (Industry Movant-Petitioners) seek the extraordinary remedy of a stay of the Rule, which EPA finalized under Section 111 to reduce emissions of methane and smog-producing volatile organic compounds from new and existing oil and gas facilities through cost-effective, achievable measures. *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 89 Fed. Reg. 16,820 (Mar. 8, 2024). Stay requests may only be granted upon a strong showing of the likelihood of success on the merits and certainty of irreparable harm. Industry Movant-Petitioners fail to show either.

Industry Movant-Petitioners' arguments focus on the Rule's requirements for owners and operators of marginal wells, which are defined as wells that produce 15 barrels of oil per day or less.[1] They incorrectly assert that EPA acted unlawfully by not conducting a formal cost-benefit analysis for the Rule's fugitive emissions monitoring and flaring requirements for marginal wells. Mot. 8-14. But Section 111 does not require such a cost-benefit analysis. Instead, EPA has broad discretion to balance economic, environmental, and energy considerations in

[1] *See* TSD 6-2. For gas wells, the equivalent production rate is 90,000 cubic feet per day or less. *Id*.

choosing an achievable emission level. *See Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). Following the same regulatory structure that EPA has employed for all prior Section 111 rulemakings, EPA considered costs in the Rule by engaging in a cost-effectiveness analysis, with specific consideration of the Rule's impacts on owners and operators of marginal wells. After considering these factors, EPA determined that the Rule's controls were cost-effective and reasonable in light of the pollution-control benefits conferred. No more was required of EPA.

Contrary to Industry Movant-Petitioners' assertions, the Rule did not adopt a "one-size-fits-all" approach toward marginal well sites. Mot. 14-17. Instead, EPA appropriately based its fugitive emissions monitoring requirements on a well site's equipment count rather than a well site's estimated emissions or production rate. Indeed, approximately half of the methane emissions from wells sites in the United States comes from marginal wells. 89 Fed. Reg. at 16,990. Taking into account the significant emissions from these wells while considering compliance costs, EPA tailored the Rule's monitoring and flaring requirements to ensure their achievability by both marginal well operators and the industry as a whole.

The equities also weigh heavily against a stay. State Respondent-Intervenors are experiencing climate change and the resulting public health harms firsthand, and urgently seek the reductions in methane and smog-producing volatile organic compounds provided by the Rule. Any delay in emission reductions from a stay would compound these significant harms. Denial of a stay, on the other hand, would not cause irreparable harm. Industry Movant-Petitioners have failed to allege any imminent cognizable harm that would justify a stay of the Rule, and instead rely on speculative claims of significant economic costs that are not supported by the record or by the experience of the many operators that have been complying with similar federal and state requirements for years.

For these reasons, this Court should deny Industry Movant's Petitioners' motion to stay the Rule.

ARGUMENT

A stay of an agency rule is "an extraordinary remedy" and it is "the movant's obligation to justify" such relief. *Cuomo v. U.S. Nuclear Regul. Comm'n*, 772 F.2d 972, 978 (D.C. Cir. 1985). To qualify, the movant must make a strong showing that they are likely to prevail on the merits of the appeal. *Virginia Petrol. Jobbers Ass'n v. FCC*, 259 F.2d 921, 925 (D.C. Cir. 1958). In addition, the movant must demonstrate irreparable harm that is "both certain and great," and that the balance of the equities and public interest weigh in favor of a stay. *See Wisconsin Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985). Industry Movant-Petitioners fail to carry this burden.

I. INDUSTRY MOVANT-PETITIONERS ARE UNLIKELY TO SUCCEED ON THE MERITS.

Industry Movant-Petitioners claim that a stay is warranted because EPA did not conduct a formal cost-benefit analysis for the Rule's fugitive emissions monitoring and flaring requirements for marginal wells, and did not account for the Rule's impact on marginal wells. Mot. 8. Neither argument has merit. EPA was under no obligation to conduct a formal cost-benefit analysis in adopting performance standards under Section 111 of the Act, and it appropriately accounted for costs in any event. Moreover, EPA carefully tailored the Rule to accommodate smaller producers.

A. EPA Appropriately Accounted for Costs in the Rule.

Under Section 111 of the Act, EPA is charged with setting standards of performance for stationary sources of air pollution that reflect "the degree of emission limitation achievable through the application of the best system of emission reduction" that EPA "determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1). In setting these standards, EPA must take into account "the cost of achieving such reduction" in air pollution, along with "any non-air quality health and environmental impact and energy requirements." *Id* § 7411(h)(1).

Contrary to Industry Movant-Petitioners' primary argument, this Court has made clear that the statute's reference to costs does not require EPA to undergo a formal cost-benefit balancing test when developing performance standards under

Section 111. *See Essex Chem. Corp. v. Ruckleshaus*, 486 F.2d 427, 437 (D.C. Cir. 1973) (cost-benefit analysis not required under Section 111).[2] Instead, EPA need only engage in a "reasoned" consideration of "economic costs as required by [Section] 111." *Id.* While "[i]t is not unlikely that industry and the EPA will disagree on the economic costs of . . . various control techniques," *id.*, EPA's evaluation of costs will stand so long as the performance standard adopted "can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way," *id.* at 433; *accord Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs . . . are exorbitant.").

Here, EPA engaged in a reasoned consideration of the Rule's economic costs. For example, consistent with EPA's long-standing approach in setting performance standards under Section 111, EPA used a "cost effectiveness analysis" to gauge

[2] Industry Movant-Petitioners' reliance on *Michigan v. EPA*, 576 U.S. 743 (2015) is misplaced. Unlike Section 111, the relevant provision of Section 112 of the Act does not expressly reference costs. *See* 42 U.S.C. § 7412(n)(1)(A). But, the *Michigan* Court held that EPA must take cost into account when determining whether regulation of hazardous air pollutants from power plants was "appropriate" under Section 112, a broad term that the Court held "requires at least some attention to cost." 576 U.S. at 752. That holding has no bearing here because EPA did consider costs as required by Section 111. And, the *Michigan* Court did not mandate a "formal cost-benefit analysis" as Industry-Movant Petitioners assert. *See id* at 759.

whether the Rule's performance standards achieve emissions reductions at a reasonable cost. *See* 89 Fed. Reg. at 16,864. This analysis examined the annualized cost of implementing each air pollution control measure divided by the amount of annual pollutant reductions realized. *Id.* These cost values were derived using "the best information available to the Agency," including studies, costs and emissions data from academia, non-governmental organizations, state and Federal agencies, and industry, along with financial information provided by small producers such as Industry Movant-Petitioners. *Id*.

After analyzing the emission reductions associated with each control option assessed for the Rule—including the fugitive emissions monitoring and flaring requirements for marginal wells—on a cost-per-ton basis, EPA determined that the cost-effectiveness values for the Rule's performance standards[3] were "reasonable" and "within the range of what the EPA has historically considered to represent cost-effective controls . . . based on the Agency's long history of regulating a wide range of industries." *Id.* EPA buttressed this finding with other evidence indicating that many industry sources had already implemented similar control measures "without deleterious effect on industry as a whole." *Id.* This Court has previously

[3] For VOC emissions, EPA found that cost-effectiveness values up to $5,540/ton of VOC reduction are reasonable, and for methane emissions, EPA found that cost-effectiveness values up to $2,048/ton of methane reduction are reasonable. 89 Fed. Reg. at 16,864-65.

approved a similar approach to EPA's consideration of costs under Section 111. *See, e.g.*, *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 191 (D.C. Cir. 2011) (EPA adequately considered the costs under Section 111 after examining the cost-effectiveness of new source performance standards for cement facilities).

In addition to determining the cost-effectiveness for each performance standard, EPA also looked at the cost of the collective standards of the Rule "in the context of the industry's overall capital expenditures and revenues." 89 Fed. Reg. at 16,865 (citing *Essex Chem. Corp.*, 486 F. 2d at 437–40; *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975)). With respect to compliance costs compared to revenues, EPA determined that the estimated total annual compliance-related expenditures would represent less than one percent of the industry's annual revenues. 89 Fed. Reg. at 16,864. Notably, these estimates do not include increased industry revenues from the sales of captured gas resulting from pollution controls, which will offset some of these costs. *Id*. In light of the modest increases in the cost of producing energy from the Rule, it cannot be said that EPA exceeded its "considerable discretion under section 111." *Lignite Energy Council*, 198 F.3d at 933.

Industry Movant-Petitioners err in claiming that EPA only looked to compliance costs on an industry-wide basis and ignored costs to smaller oil and gas producers. Mot. 19-20. While EPA was only required to account for the "economic costs to the industry" as a whole, *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 387-88 (D.C. Cir. 1973), EPA specifically responded to the cost concerns regarding marginal wells that the Industry Movant-Petitioners raised, and it tailored the Rule's requirements accordingly. *See, e.g.*, 89 Fed. Reg. at 16,905-06, 17,026-27. For purposes of the fugitive emissions monitoring requirements, EPA determined that marginal wells would generally be classified as small (or single wellhead only) well sites and therefore subject to the least stringent standard, costing an estimated $336-$660 per site per year, *see* TSD 6-8, with a cost-effectiveness of $591 per ton of methane and $2,124 per ton of volatile organic compounds reduced, *see* 87 Fed. Reg. 74,702, 74,730 (Dec. 6, 2022). EPA also recognized that this streamlined monitoring approach would reduce the regulatory impacts on small entities. 89 Fed. Reg. at 17,026-27 (the use of audible, visual, and olfactory ("AVO") inspections at small well sites "benefit[s] small entities," as they "are effective at identifying the types of large emissions from sources located at these wells sites at a much lower cost than [optical gas imaging] surveys.").

Finally, EPA did not irrationally balance domestic costs against global benefits as Industry Movant-Petitioners contend. Mot. 12. In addition to projecting the emissions reductions, costs, and benefits of the Rule pursuant to Executive Order 12866, 89 Fed. Reg. at 16,835-36, EPA separately examined the domestic quantitative and qualitative benefits of the regulation—including benefits to the climate, environment, and human health through reductions in methane and volatile organic compounds—against the domestic costs of compliance, *id.* at 16,866-67. Specifically, EPA estimated that the Rule will prevent approximately 58 million tons of methane, 16 million tons of smog-producing volatile organic compounds, and 590,000 tons of air toxics from being released into the atmosphere between 2024 and 2038. *Id*. at 16,836. Methane is a climate "super pollutant" that is a far more potent contributor to climate change than carbon dioxide in the short-term, and is responsible for approximately one-third of the current climatic warming stemming from human activities. 89 Fed. Reg. at 16,823. Further, the oil and gas sector is the largest industrial emitter of methane in the United States. *Id*. "In consideration of all of this information," EPA concluded that "the advantages that the rule provides—namely in the form of a substantial and meaningful reduction in methane and [volatile organic compound] pollution, and the associated positive impacts on public health and the natural environment—outweigh its disadvantages, namely the cost of industry compliance in the context of the industry's revenue and expenditures." *Id*. at 16,868 (internal cross-reference omitted).

B. The Rule's Treatment of Marginal Wells Is Rational.

Industry Movant-Petitioners further err in arguing that EPA acted arbitrarily by adopting a "one-size-fits-all" approach toward marginal wells. Mot. 14-20.

Industry Movant-Petitioners make two arguments to support this claim: that the Rule arbitrarily based its fugitive emissions monitoring requirements on a well site's equipment count, and that the Rule's fugitive emissions and flaring requirements are not "achievable" for marginal wells as required under Section 111. Mot. 14-15. Neither argument has a substantial likelihood of success.

First, EPA "articulated a satisfactory explanation" for its decision to base the rigor of its fugitive emissions monitoring requirements on a well site's equipment count, stating "a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins*., 463 U.S. 29, 43 (1983). The Rule's purpose is to "mitigate climate-destabilizing pollution and protect human health by reducing greenhouse gas (GHG) and VOC emissions from the oil and natural gas industry." 89 Fed. Reg. at 16,822. After evaluating extensive data and information in the record, EPA found that "the frequency and magnitude of emissions from well sites are more strongly correlated with equipment counts than with production rates." *Id*. at 16,906. Accordingly, EPA determined that well sites with higher equipment counts required more rigorous emissions monitoring using approved surveying instruments, and "Small Well Sites," defined as well sites containing only one or fewer pieces of certain equipment, required less expensive emissions monitoring via AVO inspections. *Id*. at 16,830, 16,905.

Instead of an equipment count approach, Industry Movant-Petitioners advocate for categorizing "Small Well Sites" based on either emissions modeling or throughput, which they claim would more fairly subject marginal wells to the less expensive monitoring requirements. Mot. 16-18. Indeed, as Industry Movant-Petitioners point out, EPA once considered categorizing wells based on approximated emissions. Mot. 16. But EPA reasonably explained its rationale for rejecting both an emissions modeling approach and a throughput approach in the Rule. Responding to concerns voiced by Industry Movant-Petitioners themselves, EPA recognized that it would be less burdensome for operators to determine a well site's compliance obligations through straightforward equipment counts, rather than relying on complicated emissions modelling. 87 Fed. Reg. at 74,724-25 (Dec. 6, 2022). Regarding a throughput-categorization, citing to newly available data from two recent scientific studies, EPA found that approximately half of the United States' methane emissions from wells sites come from low-production well sites. 89 Fed. Reg. at 16,990. And, these studies showed that the wells with the smallest emissions rates were *not* the wells with the lowest production. *Id*. Notably, the complete data sets from these studies were not available when EPA first proposed its calculation-based categorization. *Id.* Accordingly, EPA reasonably explained the Rule modification between proposal and finalization: EPA received new information showing that equipment counts more efficiently and more effectively correlates with emissions.

Second, Industry Movant-Petitioners err in claiming that the Rule is unlawful because its fugitive emissions and flaring requirements are not "achievable" for marginal wells as required under Section 111. Mot. 15. "An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not be routinely achieved within the industry prior to its adoption." *Essex Chem. Corp.*, 486 F.2d at 433-34. To the extent that Industry Movant-Petitioners claim that the Rule's standards are not achievable for marginal wells due to the expense, Mot. 14-15, as discussed above, EPA explained how marginal wells could afford these requirements, *see supra* Section I.A.

Furthermore, EPA had ample evidence before it that the Rule's requirements for marginal wells are plainly achievable despite their additional expense, as the oil and gas industry has been meeting similar, and more stringent, state regulatory programs for years. California, Colorado and New Mexico all have fugitive emissions requirements which mandate the use of approved surveying instruments, with up to monthly frequencies. Ex. A, Comment of States and Cities at 6-7; Ex. B, Comment of Colorado Local Government Coalition at 17; *see also* Ex. C, Miano Decl. ¶ 9. Colorado and New Mexico have even stricter venting and flaring requirements than the Rule, with both States prohibiting routine flaring and venting. Ex. A, at 14-15; Ex. B at 6-7, 9-13; *see also* Miano Decl. ¶ 8. None of these States provide exemptions for marginal wells. Ex. A. at 6-7, 14-15; Ex. B at 6-7, 9-13, 17; *see also* Miano Decl. ¶ 8-9. With some of these regulations in place for over a decade, these States have still remained top oil and gas producers in the nation. For example, New Mexico is the country's number two onshore oil producer, and number six onshore gas producer. Miano Decl. ¶ 5. Notably, 34,231 of New Mexico's over 51,434 active oil and gas wells are considered marginal, yet continue to successfully operate under the state's regulatory scheme. Miano Decl. ¶ 6. In fact, since implementing its regulatory program, New Mexico has not "seen a significant increase in the number of operator bankruptcies, an increase in the number of inactive wells, or a decline in the number of permits being submitted." Miano Decl. ¶ 13. Instead, oil and gas production continues to grow. Miano Decl. ¶ 11.

Moreover, the Rule includes numerous flexibilities to accommodate a range of wellsite conditions that could impact marginal wells. *See Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980) (explaining that an agency must describe "how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated"). EPA tailored its fugitive emissions program to accommodate a variety of conditions: equipment counts, the presence of processing equipment, and geographic location. 89 Fed. Reg. at 16,830. Additionally, the Rule lifts its prohibition on routine flaring for existing wells with documented low emissions or demonstrated technological infeasibility. *Id*. at 16,889. There is also flexibility at the state implementation stage where "States can consider the RULOF [remaining useful life and other factors]-specific situations at the low associated gas production wells that do not have flares or other control devices onsite," creating the potential for further individualized accommodations. *Id.* at 16,947. New oil wells also have multiple compliance options, including sales-line routing, but also using gas as on-site fuel, injecting it into a well, and temporarily using flares or other controls. *Id.* at 16,886. Given all of these built-in flexibilities, Industry Movant-Petitioners' description of an unachievable "one-size-fits-all" program is a clear mischaracterization of the Rule. Mot 14.

II. INDUSTRY MOVANT-PETITIONERS HAVE NOT DEMONSTRATED IRREPARABLE HARM.

In addition to showing a likelihood of success on the merits, to obtain a stay, Industry Movant-Petitioners must demonstrate that their economic harm is "both certain and great" and "imminen[t]." *Wisconsin Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985). Industry Movant-Petitioners' speculative claims of economic harm are neither "certain" nor "imminent," and do not justify a stay.

Industry Movant Petitioners' motion rests on the alleged economic harm from complying with the Rule's requirements for existing marginal wells, which they claim "will be immediately imposed." Mot. 20. However, the marginal wells that they allege will be closed are almost entirely existing sources not subject to any near-term requirements. The Rule's emission guidelines for existing wells do not require Industry Movant-Petitioners to "immediately" change any operations within the period relevant for a stay. As detailed in the responses filed to State Petitioners' Motion to Stay, the emission guidelines do not regulate existing sources directly but instead guide States in developing plans that establish existing-source standards. 42 U.S.C. § 7411(d). States have twenty-four months to submit plans, and the compliance deadline for sources is thirty-six months after state-plan submission. 89 Fed. Reg. at 17,010-11. Sources thus have "up to 5 years between when the [emission guidelines] are final and when they are required to fully comply with the applicable standards." 89 Fed. Reg. at 17,012. The Rule's emission guidelines thus have no immediate impact on Industry Movant-Petitioners that could justify a stay pending litigation.

Nor do Industry Movant-Petitioners demonstrate any certainty of harm. They claim that the Rule's exorbitant costs will result in closure of "hundreds of thousands" of marginal wells, chill the development of approximately forty-two new marginal wells in Michigan, and eliminate related jobs. Mot. 5-7. But these claims are speculative and lack support in the record. As explained, *supra* I, EPA has taken reasonable steps to lessen the Rule's impact on smaller producers. In addition, as EPA noted, many factors such as age, location, and what is produced from each marginal well contribute to differences in baseline regulatory costs for well owners. RIA 4-21 – 4-22. Further, many operators have already been complying with similar federal and state requirements for marginal wells for several years. *See supra* Section I.B. Therefore, the associated compliance costs are only an incremental increase and not exorbitantly cost-prohibitive, and Industry Movant-Petitioners' offer no evidence otherwise.

Finally, the harm asserted by Industry Movant-Petitioners from the Rule does not align with the relief requested. Industry Movant-Petitioners seek a stay of the Rule in its entirety but only allege harm from complying with the requirements for marginal wells. But this Court has "long held that [a]n injunction must be narrowly tailored to remedy the specific harm shown." *Nebraska Dep't of Health & Hum. Servs. v. Dep't of Health & Hum. Servs*., 435 F.3d 326, 330 (D.C. Cir. 2006) (internal quotations omitted).

III. A STAY WOULD HARM STATE RESPONDENT-INTERVENORS AND IS NOT IN THE PUBLIC INTEREST.

Even if Industry Movant-Petitioners had demonstrated harm, it would have to be weighed against "harm on other interested parties" if a stay is granted. *Ambach v. Bell*, 686 F.2d 974, 979 (D.C. Cir. 1982). The Court must consider "the interests of . . . stakeholders who supported the rule and who . . . stand to suffer harm" if the Rule is enjoined. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 557 (D.C. Cir. 2015). Here, any delay to the Rule's deadlines to limit methane emissions from new and existing oil and gas sources would harm State Respondent-Intervenors.

Methane is a potent climate "super pollutant" and the oil and gas sector is the largest industrial emitter of methane in the United States. 89 Fed. Reg. at 16,823. State Respondent-Intervenors have a significant interest in reducing those emissions and will be severely harmed if a stay foregoes those reductions. State Respondent-Intervenors are currently experiencing significant climate harms that are projected to worsen without deep reductions in anthropogenic emissions of greenhouse gases. *See* 89 Fed. Reg. at 16,839 (identifying impacts specific to the United States including severe drought, outbreaks of insects that could affect crops, severe wildfires and wildfire smoke, coastal flooding, storm surges, and sea level rise impacting current real estate and infrastructure along coastlines.); *see also* State Response ECF No. 2053101; Soleau Decl. ¶¶ 7-25; Fleishman Decl. ¶¶ 7-26; Chamberlin Decl. ¶¶ 6-15. These climate impacts cause direct injuries to State Respondent-Intervenors through loss of state coastline and coastal property; damages to state parks, public lands, and cultural resources; and increased expenditure of funds on drought, wildfire, storm, and flood preparation, protection of public health, and strengthening and repairing infrastructure impacted by extreme weather. State Response ECF No. 2053101; Chamberlin Decl. ¶¶ 9-14; Soleau Decl. ¶¶ 16-20; Fleishman Decl. ¶¶ 13-14, 24-26. These impacts will only get worse, and their costs mount dramatically, if greenhouse gas emissions continue unabated or increase. State Response ECF No. 2053101; Chamberlin Decl. ¶ 15; Soleau Decl. ¶ 7.

Staying the Rule would also delay significant health and environmental benefits from a reduction in volatile organic compounds and other hazardous pollution that worsens our air quality, harms our residents' health, and strain our healthcare systems—especially in overburdened communities. 89 Fed. Reg. at 16,836-41. Emissions of volatile organic compounds from the oil and gas sector also contribute to nonattainment of national ambient air quality standards for ozone. RIA at 3-26 ("Recent observational and modeling studies have found that [volatile organic compound] emissions from oil and natural gas operations can impact ozone levels"). A stay of the Rule would delay reductions in smog-forming volatile organic compounds thereby impeding states' abilities to meet the obligations under Section 110 of the Act.

Finally, a stay would create regulatory uncertainty around the process of state plan developments, making it more difficult for state planners in State Respondent-

Intervenors and elsewhere to move state plans forward. *See* State Response ECF No. 2053101; Lozo Decl., ¶ 25. Weighing the equities thus militates against a stay.

CONCLUSION

Industry Movant-Petitioner's motion to stay the Rule should be denied.

Dated: June 11, 2024

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

I hereby certify that the opposition complies Fed. R. App. P. 27(d)(2)(A) because it contains 4,151 words, excluding the parts of the motion exempted under Fed. R. App. P. 32(f), according to the count of Microsoft Word.

I further certify that this filing complies with the requirements of Fed. R. App. P. 27(d)(1)(E) because it has been prepared in 14-point Times New Roman, a proportionally spaced font.

Dated: June 11, 2024

/s/ Kavita Lesser
KAVITA LESSER

CERTIFICATE OF SERVICE

I hereby certify that the foregoing opposition was filed on June 11, 2024 with the Clerk of the Court for the United States Court of Appeals for the District of Columbia Circuit through the Court's CM/ECF system and that, therefore, service was accomplished upon counsel of record by the Court's system.

Dated: June 11, 2024

/s/ Kavita Lesser
KAVITA LESSER

Exhibit A

States of California, et al., Comments on "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 Fed. Reg. 74,702 (Dec. 6, 2022), EPA-HQ-OAR-2021-0317-2410

States of California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Oregon, Vermont, Washington, Wisconsin, the Commonwealths of Massachusetts and Pennsylvania, the District of Columbia, and the City of Chicago

February 13, 2023

Via Electronic Transmission

EPA Docket Center (EPA/DC)
Docket ID No. EPA-HQ-OAR-2021-0317
U.S. Environmental Protection Agency
Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
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RE: Comments on "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 Fed. Reg. 74,702 (Dec. 6, 2022)

Attention: Docket ID No. EPA-HQ-OAR-2021-0317

Dear Administrator Regan,

The States of California,[1] Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Oregon, Vermont, Washington, Wisconsin, the Commonwealths of Massachusetts and Pennsylvania, the District of Columbia, and the City of Chicago (States and Cities) respectfully submit these comments on the Environmental Protection Agency's (EPA) supplemental notice of proposed rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 Fed. Reg. 74,702 (Dec. 6, 2022) (Supplemental Proposal).

The Supplemental Proposal updates, strengthens, and expands the standards proposed on November 15, 2021 to reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from new modified and reconstructed facilities, as well as from existing facilities, in the oil and natural gas sector.[2] EPA anticipates that the Supplemental Proposal will result in

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[1] The California Attorney General submits these comments pursuant to his independent power and duty to protect the environment and natural resources of the State. *See* Cal. Const., art. V, § 13; Cal. Gov. Code, §§ 12511, 12600-12612; *D'Amico. v. Bd. of Medical Examiners*, 11 Cal.3d 1, 1415 (1974).

[2] 86 Fed. Reg. 63,110 (Nov. 15, 2021) (2021 Proposal). The States and Cities submitted detailed comments on the 2021 Proposal. *See* EPA-HQ-OAR-2021-0317-1267. Thus, to the extent the Supplemental Proposal references and relies on issues, analyses, and conclusions noted in the 2021 Proposal, the States and Cities expressly incorporate all comments and supporting

(continued…)

approximate emissions reductions, in the years 2023 to 2035, of 36 million tons of methane, 9.7 million tons of smog-forming volatile organic compounds (VOCs), and 390,000 tons of air toxics. Further, EPA determined that the net economic benefits of the rule will outweigh the costs, taking into consideration the avoided social costs imposed by GHG emissions and the industry's ability to sell the natural gas that will be captured by the new controls.

We support EPA's continued efforts to further reduce methane emissions from the oil and natural gas sector. The Supplemental Proposal has addressed several issues that were raised in our comments on the 2021 Proposal, including: (1) a revised approach for fugitive emissions monitoring and repair at all well sites, based on the specific types of equipment rather than well production, that continues until a site has been properly closed, including plugging the wells at the site and submitting a well closure plan; (2) a zero-emissions standard for pneumatic controllers and pneumatic pumps at affected facilities in all segments of the industry; and (3) a requirement that owners and operators of oil wells with associated gas must implement alternatives to flaring the gas unless it is not feasible for demonstrated technical or safety reasons.

We are also encouraged by EPA's proposed super-emitter response program. Studies show that emissions from a small number of oil and natural gas sources are responsible for a significant portion of the industry's emissions. The proposed program allows regulatory authorities or qualified third parties to notify owners and operators of regulated facilities when a super-emitting event (defined as emissions of 100 kilograms of methane per hour or larger) is detected. Owners and operators would then be required to conduct an analysis within five days of receiving notification to determine the cause of the event, and be required to take corrective action within ten days. The program will hopefully empower underserved[3] and overburdened communities that are often affected by nearby oil and gas infrastructure.

For these reasons, and as detailed below, we strongly support EPA's Supplemental Proposal. We further believe that certain elements of the Supplemental Proposal should be strengthened, including, but not limited to: requiring a shorter repair period if the well site is located in proximity to an already overburdened community; adding restrictions on the amount

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documents previously submitted, including the supporting materials submitted as Attachments 1 through 29. Additional supporting materials are submitted with these comments as Attachments 30 through 40.

[3] "Underserved communities" refers to populations sharing a particular characteristic, as well as geographic communities, that have been systematically denied a full opportunity to participate in aspects of economic, social, and civic life, such as Black, Latino, and Indigenous and Native American persons, Asian Americans and Pacific Islanders and other persons of color; members of religious minorities; lesbian, gay, bisexual, transgender, and queer (LGBTQ+) persons; persons with disabilities; persons who live in rural areas; and persons otherwise adversely affected by persistent poverty or inequality. *See* Exec. Order 13,985, Advancing Racial Equity and Support for Underserved Communities Through the Federal Government, 86 Fed. Reg. 7009 (Jan. 25, 2021).

of time that operators are allowed to idle wells and limiting the number of idle wells that an individual owner can hold; prohibiting routine flaring with an exception only for safety and emergencies; revisiting potential regulatory options for "pigging" operations; lowering the threshold for defining super-emitter emission events; clarifying super-emitter reporting requirements; and designing the super-emitter response program to maximize community participation.

I. LEGAL JUSTIFICATION FOR THE PROPOSED RULE

The States and Cities reaffirm our support of EPA's legal and factual findings for the 2021 Proposal and the Supplemental Proposal. Under section 111 of the Clean Air Act, EPA must establish a list of source categories and "shall include a category of sources in such list if in [the EPA Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Once it has listed a source category, EPA "shall" promulgate "standards of performance" limiting emissions of certain pollutants from new sources in that source category.[4] A "standard of performance" means "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[5] When EPA establishes performance standards for new sources in a particular source category, EPA is also required under section 111(d) of the Clean Air Act and applicable regulations to publish guidelines for controlling emissions from existing sources in that source category, subject to two narrow exceptions that are not applicable here.[6] After EPA issues final guidelines for existing sources of a designated pollutant, states must submit plans containing emission standards for control of that pollutant from designated facilities within the state.[7]

In 1979, EPA listed crude oil and natural gas production under section 111 of the Clean Air Act as a source that "contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare."[8] In 1985, EPA promulgated new source performance standards for the oil and natural gas source category that regulated emissions of VOCs and sulfur dioxide.[9] In 2012, EPA updated the new source performance standards to establish VOC standards for several oil and natural gas-related operations not previously covered.[10] Also in 2012, EPA evaluated methane emissions from the oil and natural gas source

[4] 42 U.S.C. § 7411(b)(1)(B).
[5] *Id.* § 7411 (a)(1).
[6] *Id*. § 7411 (d).
[7] 40 C.F.R. § 60.23a(a)(1).
[8] *See* Priority List and Additions to the List of Categories of Stationary Sources, 44 Fed. Reg. 49,222 (Aug. 21, 1979).
[9] 50 Fed. Reg. 26,122 (June 24, 1985); 50 Fed. Reg. 40,158 (Oct. 1, 1985).
[10] 77 Fed. Reg. 49,490 (Aug. 16, 2012).

category, but did not take action.[11] In 2016, EPA issued new source performance standards directly regulating methane emissions from the oil and natural gas sector for the first time.[12]

To date, the oil and natural gas sector remains the largest industrial emitter of methane in the United States.[13] Methane is a potent GHG that has eighty-three times the warming impact of carbon dioxide for the first two decades after release and approximately thirty times the warming impact over a one hundred-year timeframe.[14] "Indeed, one third of the warming due to GHGs that we are experiencing today is due to human emissions of methane."[15] As we experience the warmest temperatures on record, threats to public health and the environment in our States and Cities continue to mount. For example, higher temperatures are linked with significant increases in "[hospital] admissions for acute renal failure, appendicitis, dehydration, ischemic stroke, mental health, noninfectious enteritis, and primary diabetes."[16] Socially-vulnerable populations—including children, elderly people, low-income communities, and people of color—are exposed disproportionally and experience greater impacts from higher temperatures.[17] Rising temperatures combined with drier conditions are also increasing the risk of wildfires.[18] "[S]ince 1984, human-induced climate change is responsible for doubling the cumulative area of

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[11] *Id.* at 49,513.
[12] 81 Fed. Reg. 35,824 (2016 Standard).
[13] 87 Fed. Reg. at 74,720.
[14] *Id*.
[15] *Id*.
[16] *See* Att. 2, Toki Sherbakov, et al., *Ambient temperature and added heat wave effects on hospitalizations in California from 1999 to 2009*, 160 Envtl. Research 83, 83 (2018); *see also* Att. 3*,* Louise Bedsworth et al., California Governor's Office of Planning and Research, *Statewide Summary Report. California's Fourth Climate Change Assessment* 38 (2018) ("High ambient temperatures have been shown to adversely affect public health via early death (mortality) and illness (morbidity).").
[17] *See* Att. 5, EPA, *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts* at 32–36 (2021), *available at* www.epa.gov/cira/social-vulnerability-report; Att. 4, Marcus C. Sarofim et al., U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*, at 45 (2016); Att. 6, Angel Hsu et al., *Disproportionate exposure to urban heat island intensity across major U.S. cities*, Nature Communications 8 (2021), *available at* https://doi.org/10.1038/s41467-021-22799-5 ("Currently disadvantaged groups suffer more from greater heat exposure that can further exacerbate existing inequities in health outcomes and associated economic burdens, leaving them with fewer resources to adapt to increasing temperature.").
[18] Att. 30, U.S. Global Change Research Program, *Fourth National Climate Assessment, Volume II: Impacts, Risks, and Adaptation in the United States* at 241 (D.R. Reidmiller et al. eds., 2018) (Fourth National Climate Assessment), available at https://nca2018.globalchange.gov/downloads/; Att. 10, Zachary A. Holden, et al., *Decreasing fire season precipitation increased recent western US forest wildfire activity*, 115 PNAS E8349, E8349 (Sept. 4, 2018) ("[D]eclines in summer precipitation and wetting rain days have likely been a primary driver of increases in wildfire area burned.").

forest fires across the western United States."[19] Climate change is also contributing to increasingly severe weather events, such as hurricanes of greater intensity, sea-level rise, and coastal flooding.[20]

The oil and natural gas sector is also a source of significant emissions of VOCs and air toxics. The public health impacts of VOCs are well documented. VOCs are a main precursor to the formation of ozone, which can cause harmful respiratory symptoms such as airway inflammation and asthma.[21] Long-term exposure to VOCs can also result in premature death from lung and heart disease.[22] Children and people with respiratory disease are most at risk.[23] Air toxics associated with natural gas, such as formaldehyde and benzene, cause cancer and other serious health effects.[24]

For these reasons, the oil and natural gas sector contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare and EPA remains statutorily obligated under section 111 to regulate emissions—including methane emissions—from new and existing sources in the oil and natural gas source category. Further, in 2016, EPA correctly determined that it had legal authority to regulate methane from the oil and natural gas source category under section 111(b)(1)(B).[25] EPA relied on overwhelming record evidence regarding the adverse impacts of methane to public health and welfare and the high quantities of methane emissions from the oil and natural gas source category, including existing sources.[26] EPA also explicitly made an endangerment and significant contribution finding with respect to GHG emissions from the oil and natural gas source category. Thus, EPA properly concluded that methane emissions must be directly addressed through standards of performance under section

[19] Att. 11, Marcus Lowe and Rebecca Marx, Datu Research, Climate Change-Fueled Weather Disasters & Costs to State and Local Economies 53 (July 2020).
[20] Fourth National Climate Assessment, *supra* n.18, at Ch. 8.
[21] 86 Fed. Reg. at 63,127.
[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] 81 Fed. Reg. at 35,841; *id.* at 35,842–43 ("When considered in total, the facts presented in . . . this preamble, along with prior EPA analysis, . . . provide a rational basis for regulating GHG emissions from affected oil and gas sources by expressing GHG limitations in the form of limits on methane emissions.").
[26] *See, e.g.*, 81 Fed. Reg. at 35,833–43 (citing to, among other things, EPA's 2009 endangerment finding for GHGs, including methane, 74 Fed. Reg. 66,496 (Dec. 15, 2009), and subsequent assessments validating and lending additional credence to such finding; the fact that the oil and natural gas source category is the largest industrial emitter of methane in the United States; and the high global warming potential of methane, which is 28 to 36 times greater than that of carbon dioxide); *cf. Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 120 (D.C. Cir. 2012) ("The body of scientific evidence marshaled by EPA in support of the [2009] Endangerment Finding is substantial.").

111(b)(1).[27] And since at least 2016, when EPA began to regulate methane from new oil and natural gas sources under section 111(b) of the Clean Air Act, EPA has been required to promulgate emission guidelines to regulate methane from existing oil and natural gas sources under section 111(d) of the Act.[28]

II. EPA'S SUPPLEMENTAL PROPOSAL IS APPROPRIATE AND REASONABLE

The States and Cities continue to support EPA's proposed new source performance standards and emission guidelines for the oil and natural gas source category. As demonstrated by the 2016 Standard, which has been in effect for several years, and the nation-leading regulatory experiences of states like California, Colorado, and New Mexico, cost-effective control technologies and practices to eliminate or substantially reduce harmful methane and VOC emissions from new and existing oil and natural gas sources are technically feasible and widely available. As noted below, the States and Cities also believe that EPA should build upon and strengthen certain elements of the Supplemental Proposal.

A. EPA's Proposed Standards for New and Existing Well Sites

The States and Cities continue to support EPA's elimination of the exemption from fugitive monitoring and repair for low production or marginal wells—including well sites with a potential to emit (PTE) of less than 3 tons per year—and are encouraged that EPA is requiring regular fugitive emissions monitoring and repair for all well sites regardless of their PTE or production level. As EPA recognizes, large leaks can happen at any time, even at well sites with low PTE, and regular monitoring is necessary to detect and mitigate those fugitive emissions.

We appreciate EPA's revised approach for fugitive emissions monitoring at all well sites based on the specific types of leak-prone equipment or equipment that can be the source of large emission events—such as flares, storage vessels, and pneumatic devices—rather than well production. Specifically, EPA has proposed that: single wellhead only facilities and "small well sites" (defined as single wellhead facilities with a single piece of major equipment and no tank battery) require quarterly audio visual and olfactory (AVO) inspections; two or more wellhead only facilities require semiannual optical gas imaging (OGI) inspections and quarterly AVO inspections; and well sites with major production and processing equipment and centralized production facilities require quarterly OGI monitoring and bimonthly AVO.[29]

EPA's revised approach seems to be largely based on Colorado's leak detection and repair (LDAR) program, which has been in place since 2014, and requires each well site to calculate its baseline methane emissions for all of the equipment at the well site, the number of fugitive emissions components associated with each piece of equipment, and the site-specific gas composition. Colorado's regulatory approach to leak detection and approved instrument

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[27] 81 Fed. Reg. at 35,833–43.
[28] *See* 42 U.S.C. § 7411(b), (d).
[29] 87 Fed. Reg. at 74,708–09 (Dec. 6, 2022).

monitoring method (AIMM) inspection of well production facilities is multi-layered. First, as of a December 2021 program update, all new well production facilities must conduct monthly AIMM inspections unless they are constructed and operated with specified design features that reduce the potential for emissions, such as constructing the site without hydrocarbon liquid storage tanks (i.e., tankless design).[30] Existing well production facilities must conduct inspections at a frequency that depends on the actual, uncontrolled VOC emissions from a storage tank.[31] Inspection frequencies range from annual, for the smallest sites, to monthly for the largest sites.[32] Colorado also incorporates stricter standards for operations in disproportionately impacted communities and, in some cases, where the operations are located within 1,000 feet of an occupied area.[33]

Alternatively, EPA may consider streamlining the proposed LDAR program by requiring the same LDAR requirements for all facilities. California's regulation requires quarterly LDAR inspections at all new and existing well sites without exemptions, and operators in California—including large and small entities—have complied with the requirements for many years now.[34] Specifically, components in place after January 1, 2018 require quarterly EPA Method 21[35] inspections.[36] OGI is permissible for leak detection and/or monitoring but may not be used in place of quarterly EPA Method 21, and the time limitations for leak repair are also applied evenly across the facilities.[37] Similarly, New Mexico's recently promulgated regulations apply LDAR requirements to all wells with no exceptions, with every well to receive leak inspections at least once a year, and larger, potentially higher emitting wells receiving semiannual or quarterly inspections.[38] And New York's recently adopted regulations require semiannual LDAR at all well sites with no exceptions.[39] Uniformity may facilitate and ensure that states are able to implement and enforce these requirements in their plans.

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[30] 5 Colo. Code Regs. § 1001-9:D.II.E.4.e-f (adopted Dec. 17, 2021).
[31] *Id.* § II.E.4.g. tbl. 4.
[32] *Id.*
[33] Colo. Rev. Stat. § 24-4-109.
[34] *See* Cal. Code Regs., tit. 17, § 95669.
[35] 40 C.F.R § 60, Appendix A7 ("Method 21: Determination of Volatile Organic Compound Leaks"). The summary of Method 21 provides that "a portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in section 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources." *Id.*
[36] Cal. Code Regs., tit. 17, 95669(g) (2018).
[37] *Id.*
[38] *See* New Mexico Administrative Code 20.2.50, at 20.2.50.16, *available at* https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2022/07/Oil-and-Gas-Sector-Ozone-Precursor-Polutants-Final-rule-20.2.50-NMAC-06Jul22.pdf.
[39] 6 New York Codes, Rules and Regulations (NYCRR) 203-7.2(a) (effective Mar. 3, 2022).

EPA has also proposed that a first attempt at repair must be made within 15 days of identifying a leak through AVO. With respect to leaks identified through OGI, EPA has proposed a first attempt at repair within 30 days, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt.[40] The States and Cities continue to recommend that EPA require a shorter repair period if the well site is located in proximity to an already overburdened community. For instance, Colorado regulations require that a first attempt at the repair of a leaking component be made within five days if a site is located within 1,000 feet of an occupied area or within a disproportionately impacted community.[41]

Finally, the undersigned support EPA's adoption of a presumptive standard for existing well sites that follows the same fugitive monitoring and repair program as for new sources. Detecting and repairing leaks does not require installation of controls on existing equipment or retrofits. Rather, as noted by EPA,[42] the technology to address methane leaks is the same at new and existing sites, as are the emission reductions, costs and cost-effectiveness. It is therefore reasonable for EPA to promulgate a presumptive standard for fugitive emissions at well sites that mirrors the new source performance standard.

B. EPA's Proposed Standards for New and Existing Compressor Stations

The States and Cities support EPA's revised approach of monthly AVO monitoring and quarterly OGI monitoring of fugitive emissions at new and existing compressor stations. California requires quarterly Method 21 inspection of compressor stations with the option of OGI monitoring, as long as a Method 21 inspection is performed in the event OGI monitoring detects a leak.[43] New York regulations require bimonthly monitoring at compressor stations using EPA Method 21, OGI, or an approved alternative that is at least as effective.[44] Colorado's regulations require quarterly inspections of fugitive VOC emissions greater than or equal to 50 tpy, bi-monthly if greater than or equal to 50 tpy and located within a disproportionately impacted community or within 1,000 feet of an occupied area, or monthly if greater than or equal to 50 tpy.[45] The States and Cities further support EPA's adoption of a presumptive standard for compressor stations in the OOOOc emission guidelines that follows the same fugitive monitoring and repair program as for new sources.[46] As EPA recognizes,[47] the BSER analysis is the same for both new and existing sources.

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[40] 86 Fed. Reg. at 63,121, Tbl. 3 ("Summary of Proposed Presumptive Standards for GHGs from Designated Facilities").
[41] 5 Colo. Code Regs. §§ 1001-9:D.II.E.6.f-g, II.E.7.b (adopted Dec. 17, 2021).
[42] 86 Fed. Reg. at 63,173.
[43] Cal. Code Regs., tit.17, §§ 95668-95669.
[44] 6 NYCRR 203-7.2(c).
[45] 5. Colo. Code Regs. 1001-9:D.II.E.3.a & Tbl. 3.
[46] 86 Fed. Reg. at 63,174.
[47] *Id*. at 63,196.

C. Advanced Methane Detection Technologies

In the 2021 Proposal, EPA proposed an alternative screening option that would allow the use of advanced methane detection technologies as an alternative to the use of ground based OGI surveys and AVO inspections to identify fugitive emissions at well sites, centralized production facilities, and compressor stations.[48] In the Supplemental Proposal, EPA notes that "[w]hile there was widespread support of the concept of an alternative screening option, the EPA still does not have enough information to conduct the requisite BSER analysis for any specific advanced measurement technology to determine whether it would qualify as the BSER for detecting fugitive emissions."[49] EPA has instead proposed a screening matrix, which specifies several different screening frequencies corresponding to a range of minimum detection levels, rather than the single screening frequency and detection level under the 2021 Proposal. The proposed alternative periodic screening approach is limited to technologies with a minimum detection threshold less than or equal to 30 kg/hr. EPA has also proposed a continuous monitoring approach as a second alternative approach to the fugitive emissions monitoring and repair program. EPA anticipates that through this alternative screening option, EPA may "gain additional information that could be used to reevaluate the BSER in a future rulemaking."[50] EPA has further proposed a pathway for technology developers and other entities to seek EPA's approval for the use of advanced measurement technologies under this alternative screening option.

The States and Cities continue to encourage EPA's support for the use of advanced methane detection technologies for identifying fugitive emissions. The State of California has partnered with private companies, federal agencies, and several academic and philanthropic entities to advance the use of remote sensing plume-mapping technology for detecting emissions. The State of California has committed $100 million towards the purchase of this type of data from satellites, which will be awarded by a competitive request for proposal process. This technology can pinpoint and quantify leaks and other emissions of methane and carbon dioxide. These efforts build upon a successful partnership between the California Air Resources Board, the California Energy Commission, and the NASA Jet Propulsion Laboratory on a statewide study to identify large methane sources across California. That study, called the California Methane Survey, used similar technology envisioned for the satellites but mounted on airplanes to "see" methane emissions. Many commercial satellite companies are in the early stages of developing and deploying satellites equipped with similar methane plume mapping instruments, along with capabilities to observe up to 25 other environmental indicators. California will continue to explore how best to use this new information to mitigate emissions even further, both in California and globally.

However, given that this technology is still emerging and developing, the States and Cities recommend that alternative screening methods (e.g., aerial surveys) should complement, and not

[48] 87 Fed. Reg. at 74,709, 74,740.
[49] *Id.* at 74,740.
[50] *Id*.

yet completely replace, traditional OGI/AIMM inspections. We further suggest that EPA let states have the flexibility to employ alternative screening after individualized review of the appropriateness of the technology, frequencies, follow-up and repair timelines, as is most effective in the region and for the sites for which the alternative screening is deployed.

D. EPA's Proposed Standards for New and Existing Pneumatic Controllers

The States and Cities support EPA's proposed definition of pneumatic controller affected facilities to include the collection of natural gas-driven pneumatic controllers at a site instead of each individual natural gas-driven controller. We further support EPA's proposal to include: (1) controllers where the emissions are collected and routed to gas-gathering flow line or collection system to a sales line, or used as an onsite fuel source and (2) self-contained natural gas pneumatic controllers.

We further support EPA's proposal to determine that zero-emission pneumatic controllers are the BSER for new and existing sources.[51] As EPA notes, most zero-emission measures for pneumatic controllers are site-wide solutions so it is practical to define the affected facility as a collection of all controllers at a site rather than each individual controller. In addition, as EPA recognizes,[52] Colorado and New Mexico have demonstrated that oil and natural gas operators can utilize zero-emitting pneumatic equipment at both new and existing sources at reasonable cost and without disrupting operations.[53] Colorado's regulations require that new well-production facilities, those constructed after May 1, 2021, and well production facilities receiving production from a newly drilled or refracked well, must use only non-emitting pneumatic controllers.[54] For other existing well-production facilities, Colorado requires a phased-in approach to retrofitting specified percentages of gas-driven pneumatic controllers with non-emitting pneumatic devices.[55] Colorado's program does not require that all gas-driven pneumatic controllers be removed or replaced. Its program focuses on the percentage of the facility production, based on liquids production that moves through a facility, and requires that a specified percentage of production move through facilities with non-emitting pneumatic controllers.[56] Colorado, however, exempts operators from complying with many components of this program if their "total statewide oil and natural gas production average[es] 15 barrels of oil equivalent or less per day per well,"[57] in addition to other limited exemptions.[58]

[51] *See id*. at 63,208–09.
[52] *Id*. at 63,204.
[53] *Id*. at 63,206.
[54] 5 Colo. Code Regs. §§ 1001-9:D.III.C.3.a, III.C.4.a (adopted Dec. 17, 2021).
[55] *Id.* § III.C.4.
[56] *Id.* § III.C.4.c.(iii) & tbl. 1.
[57] *Id.* § III.C.4.c.(iv).
[58] *Id.* § III.C.4.e.(i).

E. EPA's Proposed Standards for New and Existing Pneumatic Pumps

The States and Cities support EPA's proposed definition of the pneumatic pump affected facility to include the collection of natural gas-driven pneumatic pumps at a site instead of each individual natural gas-driven pump. We further support EPA's proposal to determine that zero-emission pneumatic pumps in all segments—specifically diaphragm and piston pneumatic pumps in the production segment and diaphragm pneumatic pumps in the transmission and storage segment—are the BSER for new and existing sources.

F. EPA's Proposed Standards for New and Existing Reciprocating Compressors and Centrifugal Compressors

The States and Cities support EPA's proposed standard that all reciprocating compressors, except those located at well sites, must replace or repair the rod packing to maintain flow rate at or below 2 standard cubic feet per minute (scfm). As demonstrated by the regulatory experience of California, repairing the rod packing is a cost-effective alternative that achieves equivalent emission reductions.[59]

With respect to centrifugal compressors, the States and Cities support EPA's proposed standard that all wet seal centrifugal compressors (except for those located at single well sites) must capture and route emissions from the wet seal fluid degassing system to a control device or to a process that reduces emissions by 95%, and all dry seal centrifugal compressors must ensure a volumetric flow rate at or below 3 scfm. Again, the regulatory experience of California supports EPA's conclusion that this proposed standard is adequately demonstrated.[60]

G. EPA's Proposed Standards for New and Existing Storage Vessels

The States and Cities support EPA's amended definition of a storage vessel affected facility as a single storage vessel or "tank battery" to include a group of all storage vessels that are manifolded together for liquid transfer. With respect to any new, reconstructed, or modified single storage vessel or tank battery with a PTE of greater than or equal to 6 tons per year (tpy) VOCs or greater than or equal to 20 tpy methane, EPA has proposed a standard of capturing and routing emissions to a control device that achieves 95 percent reduction emissions. For existing storage vessels, any single storage vessel or tank battery with a PTE of greater than or equal to

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[59] *See* Cal. Code Regs., tit. 17, § 95668(c)(3)(D); *see also* 6 NYCRR 203-4.4 (requiring reciprocating compressor with rod packing or seal with a measured emission flow rate greater than 2 scfm to be successfully repaired within thirty (30) days).

[60] *See* Cal. Code Regs., tit. 17, § 95668(c)(3)(D); *see also* 6 NYCRR 203-4.3 (beginning January 1, 2023, requiring centrifugal compressors with wet seals to control the wet seal vent gas with the use of a vapor collection system or replace the wet seal with a dry seal; the vapor collection system must direct collected vapors to a sales gas system, a fuel gas system, or a vapor control device that achieves at least 95% control efficiency; a centrifugal compressor with a wet seal emission flow rate greater than 3 scfm must be repaired within thirty (30) days).

20 tpy for methane must capture and route emissions to a control device that achieves 95 percent reduction emissions.[61] EPA should consider lowering the applicable threshold. For example, Colorado requires the control of all new and existing storage tanks emitting 2 tpy of VOC or more,[62] Pennsylvania requires controls if VOC emissions exceed 2.7 tpy, and New Mexico has adopted a threshold of 2 tpy of VOC for new tanks, 3 tpy of VOC for existing tanks in multi-tank batteries, and 4 tpy for existing tanks in single tank batteries.[63]

H. EPA's Proposal to Require Monitoring of Wells Until Submission of Well Closure Plans and Proper Plugging Will Help Prevent Wells from Becoming Orphaned

The States and Cities support EPA's proposed adoption of new source performance standards and emission guidelines that require fugitive emission monitoring and repair at all well sites to continue until a site has been properly closed, including plugging the wells at the site and submitting a well closure plan.[64] Requiring LDAR at all well sites, including wellhead only and small well sites, until closure will help address concerns cited in our comments on the 2021 Proposal regarding continuing emissions from orphaned wells and unplugged idle wells. These wells are a huge source of methane emissions and impose substantial burdens on states and taxpayers. EPA's 2022 Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI) estimates that there are around 3.7 million abandoned oil and gas wells in the U.S., and that in 2020 abandoned oil wells emitted 219,000 metric tons of methane and abandoned gas wells emitted 57,000 metric tons of methane.[65]

The States and Cities also support EPA's proposal to require that, prior to ceasing regular monitoring, owners and operators be required to conduct a survey of the well site using OGI after well closure activities have been completed. This will help ensure that the well has been properly plugged since improperly plugged abandoned wells are still a significant source of methane emissions.[66]

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[61] *See* 86 Fed. Reg. at 63,201.
[62] 5 Colo. Code Regs. § 1001-9:D.II.C.1.c.
[63] New Mexico Administrative Code 20.2.50, at 20.2.50.123(A), *available at* https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2022/07/Oil-and-Gas-Sector-Ozone-Precursor-Polutants-Final-rule-20.2.50-NMAC-06Jul22.pdf
[64] 87 Fed. Reg. at 74,736 (NSPS OOOOb) & 74,737 (EG OOOOc).
[65] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, *1990-2020*, at p. 3-108 [2021 GHGI], *available at* https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020. These numbers are likely an underestimate. *See* Att. 29, Williams et al., *Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States*, 55 Env. Sci. Tech. 563 (2020) (finding that annual methane emissions from abandoned wells are underestimated by 20% in the U.S.).
[66] 2021 GHGI, *supra* n.65, at p. 3-110 (Tables 3-101 & 3-102).

As we had recommended in our comments on the 2021 Proposal,[67] we also agree with EPA's proposal to require submission of a well closure plan prior to closure and agree that such plan should, at a minimum, describe how and when all wells at a well site will be closed and demonstrate the financial capacity to do so, including providing for financial assurance to complete closure. EPA's proposal to require owners and operators to submit the well closure report within 30 days of cessation of production from all wells at the well site and to notify the agency 60 days before beginning well closure activities is reasonable. In the final rule, EPA should clarify that, for existing wells, the emission guidelines (OOOOc) require owners and operators to submit the well closure report and the required 60-day notice to the state regulatory agency in addition to EPA.

EPA is soliciting comment on additional provisions that could be added to ensure that companies remain engaged with the site until all wells at a site are properly closed, including for instance automatic consequences for missed monitoring reports.[68] The States and Cities support the addition of such provisions. In particular, an automatic consequence for an owner's or operator's repeated failure to submit monitoring reports should include a requirement to permanently cease production, submit a well closure report, and permanently plug all wells at the site. When owners and operators are no longer monitoring and staying engaged with well sites there is a greater potential for them to deteriorate and leak or become orphan wells. By requiring owners and operators to close well sites as an automatic consequence of failure to comply with monitoring requirements, the new source performance standards and emission guidelines will incentivize owners and operators both to comply with monitoring requirements and to either produce or plug wells, rather than leaving them idled and unplugged or abandoning them to become orphan wells.

As we noted in our comments on the 2021 Proposal, EPA should also consider adding restrictions on the amount of time that operators are allowed to idle wells and limit the number of idle wells that an individual owner or operator can hold.[69] For instance, under New Mexico's regulations, an operator is allowed to idle no more than a certain percentage of its wells: two wells or 50 percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less; five wells if the operator operates between 101 and 500 wells; seven wells if the operator operates between 501 and 1,000 wells; and 10 wells if the operator operates more than 1,000 wells.[70] New Mexico also requires operators to either properly plug and abandon a well or place the well in approved temporary abandonment after drilling operations have been suspended for 60 days, the well has been determined to be no longer usable for beneficial purposes, or the well has been inactive for one year; and limits the time allowed for approved temporary abandonment to five years.[71] The longer wells are allowed to remain idle, the greater

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[67] *See* States and Cities Jan. 31, 2022 Comments, EPA-HQ-OAR-2021-0317-1267, at 21.
[68] 87 Fed. Reg. at 74,736.
[69] *See* Att. 21, IOGCC, *Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021* (detailing state regulatory strategies for addressing orphaned wells).
[70] 19.15.5 NMAC.
[71] 19.15.25 NMAC.

potential that they will become orphan wells. Also, a high percentage of idle wells may indicate an increased vulnerability of the owner becoming insolvent and leaving orphan wells.

Finally, the States and Cities support EPA's proposal to require reporting, through the annual report, of any changes in ownership at individual well sites. We agree that such a requirement will help prevent well sites from becoming orphaned by providing clarity as to who the responsible owners and operators are until the site is plugged and closed and LDAR is no longer required.

I. EPA Should Strengthen Its Proposed Standards for Associated Gas from Oil Wells to Prohibit Routine Flaring with the Only Exceptions for Safety and Emergencies

The undersigned States and Cities continue to urge EPA to adopt New Source Performance Standards (NSPS) and emission guidelines that effectively prohibit routine flaring of associated gas from new and existing oil wells, with the only exceptions related to safety and emergencies, by requiring owners or operators to capture all or a majority of the gas. Flaring is a major source of emissions of many harmful air pollutants. When functioning properly, flares emit large amounts of carbon dioxide and nitrogen oxides. When malfunctioning, which is common, they emit substantial amounts of methane, VOCs, and hazardous air pollutants directly into the atmosphere.[72]

As EPA recognizes,[73] several states have adopted standards to further reduce routine flaring of associated gas, including Colorado and New Mexico. Since 2020 Colorado has prohibited the routine flaring and venting of gas. Flaring is permitted during well production only if conditions at the well are disrupted or with written permission during maintenance, production evaluation, or as part of an approved gas capture plan.[74] The gas capture plan may allow wells in production prior to January 15, 2021 that are flaring or venting because they are not connected to a natural gas gathering line or putting the gas to beneficial use, to vent or flare for a period not to exceed 12 months, when the operator can show that it is necessary to produce the well, will minimize waste, and will minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.[75] If an operator does not connect its facility to a gathering line or otherwise put gas to a beneficial use as described in its gas capture plan, it may

[72] *See, e.g.*, Environmental Defense Fund, *Permian Methane Analysis Project*, *available at* https://data.permianmap.org/pages/flaring (finding in seven random surveys of routine-flaring sites, flare malfunctions ranged from 3.3% to 11.5% and when expanded to all well sites, including lower-production wells, flare malfunctions jumped from 29% to 36%).
[73] 87 Fed. Reg. at 74,780.
[74] 2 Colo. Code Regs. § 404-1-903.d.(1).
[75] *Id*. § 404-1-903.d.(3).

be required to shut in a well until it is connected to a gathering line or the gas is put to beneficial use.[76]

New Mexico's waste prevention regulations adopted in May 2021 further support that a prohibition on flaring is adequately demonstrated as the BSER. New Mexico's regulations prohibit routine venting or flaring and provide for a phased approach to require capture of at least 98% of gas produced by end of 2026.[77] At Phase 1, operators must collect and report data to identify the sources of emissions (from wellhead to processing and beyond) and then benchmarks are set for each operator.[78] At Phase 2, operators must show increasing progress until they reach the 98% capture threshold.[79] In addition, vented and flared gas are considered waste and subject to payment to the state of royalties and taxes.[80]

EPA should follow the states' lead and prohibit routine flaring of associated gas from new and existing oil wells except in very limited cases such as emergencies and for safety reasons. If EPA continues to allow flaring of associated gas for technical feasibility reasons, EPA also should take steps to disallow the indefinite continuation of routine flaring. The States and Cities believe that it would be appropriate to limit the allowable time for flaring to 12 months. If after 12 months an owner or operator does not connect its facility to a gathering line or otherwise put gas to beneficial use, EPA should require the operator to shut in a well until it is connected to a gathering line or the gas is put to beneficial use.

At a minimum, EPA should further strengthen flaring restrictions to ensure that the need to flare is well-documented, continues to be necessary, and does not become routine. EPA should require more frequent certifications than annual reports to demonstrate why all potential beneficial uses, including emerging techniques, are not feasible due to technical or safety reasons. When there is any change in circumstances, owners and operators should be required to perform a more thorough analysis and engineering certification comparable to the initial certification required once an owner or operator becomes subject to the rule. For instance, we agree, as EPA suggests, that it would be appropriate to require an owner or operator to provide an additional engineering certification that flaring is the only option where a new gathering pipeline is installed within a certain distance of an oil well.

J. EPA Should Consider Standards for Pigging Operations

The States and Cities encourage EPA to revisit potential regulatory options for "pigging operations," which are maintenance activities performed on a daily, weekly, or monthly basis to prevent buildup of natural gas condensates in field gas gathering and transmission pipelines. These operations require a facility to vent and blowdown any pressure in the line prior to

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[76] *Id.* § 404-1-903.e.(3).
[77] 19.15.28 NMAC.
[78] *Id.*
[79] *Id.*
[80] *Id.*

removing the device known as a pipeline intervention gadget or "pig." As demonstrated by regulations adopted by New Mexico, Colorado, and Pennsylvania, cost effective and technically feasible best practices exist to reduce emissions from pigging operations by reducing the flashing of hydrocarbons entrained in the liquids when the pigging unit is opened to remove the pig.

New Mexico has adopted a comprehensive emission reduction and LDAR strategy for pigging operations located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations.[81] Colorado's rule covers pigging units at natural gas compressor stations, natural gas processing plants, and "stand alone pigging stations" that are not located within the boundaries of other regulated facilities. Colorado relies upon a matrix of the size and pressure of the pigging pipeline to determine applicability of capture requirements. Colorado requires all operating pressure over 500 psig to employ capture or control techniques and also requires the capture of gas emitted during pigging. For smaller size and lower pressure pigging pipelines, Colorado determined that an emissions-based threshold was an appropriate approach. These thresholds are based on the location of the pigging unit, and depend on the type of location, such as whether the unit is located in a disproportionately impacted community (more stringent thresholds apply to sources in disproportionately impacted communities). In Pennsylvania, General Permit-5A regulates emissions from Unconventional Natural Gas Well Site Operations and Remote Pigging Stations, and requires quarterly LDAR for sources at unconventional natural gas well sites or remote pigging stations.[82] Given these state regulatory programs, the States and Cities request that EPA consider similar requirements in future rulemakings.

K. The Super-Emitter Response Program Is an Important Compliance Assurance Tool

The States and Cities support EPA's proposal to create a super-emitter response program, in recognition of the fact that a small proportion of sources contribute to more than half of total methane emissions.[83] These super-emitters are a significant source of methane and VOC emissions, and a single super-emitter emissions event can have substantial health and safety impacts for neighboring communities. EPA's super-emitter response program will serve as an important backstop to the proposed rule's performance standards and presumptive standards by identifying and promptly mitigating large emissions events that may not be detected by routine monitoring. The States and Cities agree with EPA's conclusion that the super-emitter response program is legally justified either by treating super-emitter emission events as a separate source of emissions for which the super-emitter response program is the BSER, or by incorporating the

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[81] *See* 20.2.50.121 NMAC.
[82] 25 Pa. Code Chapter 127, Subchapter H (General Plan Approvals and Operating Permits).
[83] Att. 31, Yuanlei Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, 56 Env. Sci. and Tech. 4317 (2022), https://doi.org/10.1021/acs.est.1c06458.

super-emitter response program into the performance standards and presumptive standards for facilities as an additional compliance assurance measure or work practice standard.[84]

EPA is soliciting comments on all aspects of the super-emitter response program. The States and Cities provide the comments below in order to maximize emissions reductions, enable community participation, promote transparency, and clarify program requirements.

1. EPA Should Maximize Emissions Reductions and Consider a Lower Threshold for Super-Emitters

The States and Cities suggest lowering the 100 kg/hr threshold for defining a super-emitter emissions event in order to identify and mitigate a wide range of emissions events. The States and Cities suggest a threshold of 70 kg/hr to ensure that the super-emitter threshold is within the range of what satellite monitoring can detect. While, as EPA notes, "no specific mass-based or production-based rates have been formally or consistently applied to the term,"[85] several studies have defined super-emitters with thresholds as low as 26 kg/hr.[86] One study applied a threshold of 26 kg/hr because it captured the highest-emitting one percent of sites, which accounted for nearly half of total site emissions in the production region.[87] A lower threshold would enable the super-emitter response program to reduce a larger quantity of methane and associated VOC emissions, while still ensuring that the program does not duplicate other requirements of the proposed rule.

As EPA notes, the super-emitter response program would largely require owners and operators to undertake actions already required by other standards and requirements of the proposed rule in order to mitigate super-emitter emissions events; the super-emitter response program would merely require that these actions be taken sooner, rather than waiting until they are detected by periodic monitoring.[88] Consequently, lowering the threshold for a super-emitter emissions event would not significantly increase costs to owners and operators, and would in fact allow facilities to recover more natural gas for sale rather than emitting the gas into the atmosphere.

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[84] 87 Fed. Reg. at 74,752–54

[85] *Id.* at 74,749.

[86] Att. 32, Daniel Zavala-Araiza et al., *Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions*, 8 Nature Commc'ns. 14012 (2017), https://doi.org/10.1038/ncomms14012; Att. 33, Daniel H. Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8 Env. Sci. & Tech. Letters 567 (2021), https://doi.org/10.1021/acs.estlett.1c00173.

[87] Zavala-Araiza et al., *supra* n.86.

[88] 87 Fed. Reg. at 74,753–54.

2. The Program Should Be Designed with Community Participation in Mind

EPA's proposed super-emitter response program is an important step to empower communities to help stem large emission events by providing a mechanism for communities and other third parties to detect and report emissions to operators. The States and Cities encourage EPA to ensure that the program is designed with community participation in mind, and that the benefits of the program will accrue to those communities that are disproportionately impacted by oil and gas facilities. EPA should ensure that the technologies that may be used to detect a super-emitter emissions event are not so restrictive that they prevent community groups from participating as third-party notifiers. For example, EPA should leverage publicly available satellite data in the super-emitter response program by permitting third parties who may not have access to remote-sensing technologies to submit notifications based on publicly available satellite monitoring data.

A third-party who chooses to become an EPA-approved notifier would do so on a voluntary and uncompensated basis. This means that private parties with access to remote-sensing technologies may have few incentives to actively participate as third-party notifiers. Communities living near oil and gas facilities, on the other hand, will have a vested interest in identifying super-emitter emissions events in order to protect their own health and safety, and such communities should be empowered to identify and report super-emitter emissions events by relying on reliable, publicly available data.

Finally, the States and Cities suggest that EPA establish a procedure for communities to report super-emitter emissions events that does not rely on the quantification of emissions. Many communities will not have access to the technologies required to quantify emissions on a kilograms-per-hour basis. The super-emitter response program should incorporate community experiences of super-emitter emissions events. Communities may experience odors, health effects, and other impacts of high levels of methane and VOC emissions, but may not have the resources or the ability to quantify the level of emissions. EPA should establish a pathway for community members to notify operators and the EPA of such health impacts. While notifications of odors and health impacts may not necessarily require an operator to take immediate corrective action, providing a mechanism for communities to report odor and health impacts would alert owners and operators of potential problems, and create a record of facilities that have frequent community impacts, allowing the EPA and states to identify facilities where compliance efforts should be focused.

3. The States and Cities Suggest Clarifications for EPA's Approval of Third-Party Notifiers and Revocation of Approval

The States and Cities support EPA's proposal to pre-approve third-party notifiers and to maintain a public list of approved third-party notifiers.[89] The States and Cities suggest that EPA

[89] *Id.* at 74,750.

further describe its proposed standards for third-party notifiers. For example, EPA could provide additional information and/or specific examples of what qualifies as an adequate "demonstration" of "the potential notifier's technical expertise in the specific technologies and detection methodologies proposed."[90] EPA could also provide application forms or templates to assist potential notifiers.

EPA is soliciting comment on whether it should establish a procedure for owners and operators to suggest that EPA reconsider the approval granted to a third-party notifier. If EPA decides to establish such a procedure, the States and Cities request that EPA provide more detail on the revocation procedure, to ensure that third-party notifiers are not denied the right to participate in the program without sufficient evidence, and to ensure that such a revocation procedure does not chill third party participation in the program.

First, EPA should provide a definition of "meaningful, demonstrable error." As EPA notes, super-emitter emissions events can be intermittent, so an operator's subsequent finding that there is no active super-emitter emissions event should not be considered evidence that the notifier demonstrably erred.[91] Operators will generally have access to much more data about their own operations than third parties using remote-sensing technologies, so it is important that EPA does not permit operators to undermine the validity of third-party notifications on those grounds alone. The States and Cities suggest that an error should only be considered "meaningful" if it results in false positive (i.e., the identification of a super-emitter emissions event when no such event occurred).

Second, EPA should clarify the process and schedule for an operator to challenge the validity of a third-party notification. The States and Cities suggest that if an operator believes a notification contains meaningful demonstrable error (and consequently, that a super-emitter emissions event did not occur), the operator must submit a report to the EPA within 10 calendar days of receiving the notification, and simultaneously submit a copy to the third-party notifier. The third-party operator would then be provided an opportunity to respond, and EPA would ultimately make a determination as to whether the notification contained meaningful, demonstrable error. The States and Cities suggest that the third party notifier be given 10 calendar days to respond, and that EPA's determination be issued 10 calendar days after that.

Third, the States and Cities request that EPA clarify that a third-party notifier's approval will not be revoked unless EPA has found demonstrable error in three of the party's notifications sent to the same site. EPA suggests that a third party's approval would be revoked after an operator has received "more than three notices at the same site and from the same third party" which contain "meaningful, demonstrable errors," but then later states that operators may seek revocation "should they establish that more than one notification contains demonstrable

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[90] *Id.*

[91] *Id.* ("Given the intermittency of super-emitter emissions events, the failure of the operator to find the source of the super-emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier.").

errors."[92] EPA should also clarify that operators must respond to a third-party's notification under the super-emitter response program (by undertaking a root cause analysis and corrective actions) unless and until a third party's approval has officially been revoked by EPA and they have been removed from EPA's list of approved notifiers.

4. The Requirements for Owner and Operator Actions and Reports Should Be Clarified

The States and Cities support EPA's suggested timelines for operator response to a super-emitter emissions event notification. Given the scale of super-emitter emissions events, it is imperative that they be addressed and mitigated promptly. EPA's proposal would require owners and operators to initiate a root cause analysis within five calendar days after receiving a third-party notification, and to complete corrective actions within 10 days of notification.[93] The States and Cities support these timelines, and provide several suggestions to clarify the actions required by owners and operators, to ensure emissions events are promptly mitigated and promote transparency.

a. EPA Should Promote Transparency by Requiring a 10-Day Status Report from Owners and Operators

EPA proposes a series of steps that an owner or operator must undertake after receiving a notification of a super-emitter emissions event. First, the owner or operator must confirm that the reported emissions event is traceable to a source located on their site and investigate to confirm if a super-emitter emissions event is still ongoing.[94] Second, the owner or operator must initiate a root cause analysis to determine the cause of the super-emitter emissions event. Third, the owner or operator must take corrective actions to mitigate the emissions. Finally, the owner or operator must submit a written report to EPA documenting the data included in the notification, the source of the emissions, the corrective actions taken to mitigate the emissions, and the compliance status of the affected facility.[95]

Under these procedures, the first time that that EPA would receive any update from the owner or operator would be 25 days after receipt of the notification, when the owner or operator submits its written report after completion of the corrective action, or 30 days after receipt of the notification, if the owner or operator determines that the corrective action would take more than 10 days to complete.[96] This means that EPA—and the public—would be in the dark for nearly one month after a super-emitter emissions event is discovered.

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[92] *Id.*
[93] *Id.* at 74,751.
[94] *Id.*
[95] *Id.*
[96] *Id.* EPA proposes that owners and operators would complete corrective actions within 10 days after receiving a notification, and submit a written report 15 days after completing the corrective action.

The States and Cities suggest that, as an intermediate step, the owners and operators be required to submit a report within 10 calendar days of receiving the notification. This 10-day report could include the following information: (1) whether the reported emissions event is traceable to a source located on the owner or operator's site; (2) whether the emissions event is ongoing, and if not, when it stopped; (3) whether the root cause analysis has been completed, and if so, the results of the analysis; and (4) whether the corrective actions are complete, and if not, justification for why additional time is needed. Additionally, as discussed above, if the owner or operator believes the notification contains demonstrable error, they could submit a report demonstrating the error in lieu of the 10-day report. EPA should also specify that a root cause analysis and corrective action(s) are required even if an owner or operator determines that the emissions event is not ongoing, unless the owner or operator can demonstrate that a super-emitter emissions event did not occur.

b. EPA Should Clarify the Timelines for Owner and Operator Actions

Under EPA's proposal, the first action that an owner or operator is required to take after receiving a third-party notification is to confirm that the reported emissions event is traceable to a source located on their site and investigate to confirm if a super-emitter emissions event is still ongoing.[97] EPA does not propose a time frame for this first step. The States and Cities suggest that owners and operators should be required to complete this first step within five calendar days after receiving the notification. This initial step is essential, as it will confirm whether the emissions are in fact attributable to the owner or operator, and whether the emissions event is ongoing. This timeline would align with the requirement that the owner or operate initiate the root cause analysis within five calendar days.

EPA proposes that owners and operators be required to complete corrective actions within 10 calendar days of receiving a notification.[98] However, EPA also proposes an alternative option when corrective actions will take more than 10 days to complete, whereby an owner or operator can develop and submit a corrective action plan 30 days after receiving a notification, describing the corrective actions completed as of that date, additional measures proposed to reduce or eliminate emissions, and a schedule for completion of those measures.[99] The States and Cites are concerned that this exemption would swallow the rule, and suggest that EPA clarify that owners and operators are expected to complete corrective actions within 10 calendar days of the notification, and must provide justification if the corrective actions are not complete in that time frame. The States and Cities suggest that this justification take the form of a 10-day status report, as described above.

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[97] *Id.*
[98] *Id.*
[99] *Id.*

5. All Notifications and Submittals Should be Submitted to the State, in Addition to the EPA

The States and Cities agree with EPA that when a third-party notifier submits a notification to an owner or operator, the party should provide a complete copy to EPA and the appropriate state authority.[100] The States and Cities believe that all subsequent reports and submittals should also be copied to the state. This will allow states to monitor compliance efforts under the super-emitter response program, and will provide valuable information that states can use in their own compliance and enforcement efforts. The States and Cities also suggest that EPA clarify that EPA will enforce the requirements of the super-emitter program. While reports submitted pursuant to the program can assist state agencies in enforcement of state regulations, enforcement of the requirements of the super-emitter response program itself should be centralized with EPA.

III. COMMENTS ON EPA'S IRA EQUIVALENCE DETERMINATION

EPA is requesting comment on how to interpret certain provisions of section 136 of the Clean Air Act added by the Inflation Reduction Act (IRA). Under section 136, certain affected facilities must pay a charge on methane emissions that exceed an applicable threshold unless and until certain conditions set forth in section 136(f) are met. Specifically, section 136(f)(6)(A) provides that charges shall not be imposed on an applicable facility that "is subject to and in compliance with" methane emission requirements pursuant to Clean Air Act sections 111(b) and 111(d) upon a determination by the EPA Administrator that: (i) such standards and plans "have been approved and are in effect in all States with respect to the applicable facilities"; and (ii) "compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by" EPA's November 2021 proposed rule.

EPA seeks comment on the proper interpretation of clause (ii) in section 136(f)(6)(A) with respect to how it should conduct the required equivalency evaluation and what factors should influence how the EPA conducts the comparison.[101] With regard to temporal elements of the equivalency evaluation, the States and Cities agree with EPA that the appropriate comparison should be based on when the NSPS or state plan requirements are fully implemented by the sources. Such an interpretation is consistent with the prefatory language in section 136(f)(6)(A), which provides that a methane charge will not be imposed only when an affected facility is "subject to and in compliance with" methane standards under section 111(b) or (d). It is also consistent with clause (i), which requires the standards and plans to have been approved and be in effect before the methane charge will no longer be imposed.

With respect to geographical elements of the evaluation, EPA requests comments on whether it should consider making a national evaluation of equivalency or whether it should consider a state-by-state evaluation instead. The States and Cities believe that the answer to this

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[100] *Id.* at 74,750.
[101] *Id*. at 74,720–22.

question depends on EPA's interpretation of the statutory language in Clean Air Act section 136(f)(6)(A)(i), which provides that, before an applicable facility can no longer be subject to the charge, the Administrator must determine that emission standards "have been approved and are in effect in all States with respect to the applicable facilities." It would be reasonable for EPA to interpret clause (ii) as allowing a national evaluation of equivalency only if EPA interprets clause (i) to mean that no affected facility in any state can avoid the charge until all states have approved state plans that are in effect. Only when all states had approved state plans in effect would EPA be able to evaluate equivalency on a national level. If, however, EPA interprets clause (i) to allow an applicable facility to avoid the change if a state plan is in effect in any state in which the applicable facility operates, then correspondingly EPA should interpret clause (ii) to require a state-by-state equivalency evaluation. Otherwise, affected facilities in a state that is not achieving emission reductions equivalent to EPA's November 2021 proposal would unfairly benefit from greater emission reductions required under more stringent requirements in another state.

EPA requests comments on whether the EPA should make the evaluation and the IRA equivalency determination in advance of states having submitted fully approvable plans or instead make the evaluation and IRA equivalency determination at a later date once the standards of performance pursuant to Clean Air Act section 111(b) and 111(d) are fully promulgated (e.g., the EPA has approved state plans and/or developed a Federal Plan). Consistent with the language in clause (i) of section 136(f)(6)(A), the States and Cities believe that EPA should make the evaluation only once the standards and state plans "have been approved and are in effect."

Finally, EPA seeks comment on how a state's invocation of remaining useful life and other factors to apply a less stringent standard to a designated facility might affect the IRA equivalency determination. Section 136 does not by its terms compel any consideration of remaining useful life and other factors in making an IRA equivalency determination. Therefore, the States and Cities believe that it would be appropriate for EPA to conduct an equivalency evaluation with respect to an applicable facility without consideration of the application of these factors.

IV. PROPOSED STATE PLAN REQUIREMENTS

This section provides the undersigned's comments on state plan issues, including equivalency, consideration of site-specific factors, community engagement, timing, and compliance.

A. Background

In the 2021 Proposal, EPA provided a general overview of the state planning process triggered by EPA's finalization of an emissions guideline for existing oil and gas facilities and included detailed requirements for state plan submittals. The States and Cities commented on numerous state plan issues, including equivalency, consideration of site-specific factors, community engagement, timing, and compliance. Among other comments, we urged EPA to: (1)

provide states with flexibility in developing their plans provided that the plans would achieve equivalent or greater emission reductions, (2) require engagement with impacted communities while providing states with additional guidance on meeting the meaningful engagement requirement, and (3) setting more expeditious deadlines for facilities that will be complying through LDAR.

In the Supplemental Proposal, EPA has proposed some revisions to the initial proposed rule and to include additional requirements to provide states with information needed for state plan development. In the discussion below, the States and Cities provide their comments on the following aspects of the Supplemental Proposal, which correspond to the organization of these topics in the preamble: state plan equivalency; remaining useful life and other factors; providing measures that implement and enforce standards of performance; emission inventories; meaningful engagement; components of state plan submission; and timing of state plan submissions and compliance times.

B. State Plan Equivalency

As set forth in our comments on the initial proposed rule, the States and Cities favor flexibility for states in designing their section 111(d) plans provided that states can demonstrate equivalent or better emission reductions from oil and gas facilities regulated by EPA's emissions guideline. In the section of the Supplemental Proposal titled "Leveraging State Programs," EPA discusses how states can achieve approval under section 111(d) for state plans that may be different in certain respects from the emissions guideline. Here, the States and Cities provide their comments on EPA's reconsideration of the prior Administration's interpretation limiting state compliance choices. With respect to other state plan equivalency issues, we refer EPA to comments submitted by our respective state agencies.

EPA proposes to interpret section 111(d) to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards. EPA explains that this approach would necessitate reversing its legal interpretation in the Affordable Clean Energy (ACE) rule that "each state establish for each source a standard of performance that reduces that source's emissions, and to preclude the type of compliance flexibility that EPA is now proposing."[102] On that basis, EPA precluded the use of emissions averaging or trading to comply with the 2019 Affordable Clean Energy (ACE) Rule. The D.C. Circuit cited this limit on state plan flexibility as one of the reasons why the ACE rule was unlawful.[103] Although the Supreme Court reversed the D.C. Circuit, holding that the ACE's rule's repeal of the Clean Power Plan was lawful under the major questions doctrine, the Supreme Court did not rule on the statutory interpretation EPA advanced in favor of the ACE rule, including the limit on compliance flexibility.[104]

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[102] 87 Fed. Reg. at 74,812.
[103] *See American Lung Ass'n v. EPA*, 985 F.3d 914, 957–58 (D.C. Cir. 2021).
[104] *See West Virginia v. EPA*, 142 S. Ct. 2587, 2615–16 (2022).

In the Supplemental Proposal, EPA explains that it has changed its view set forth in the ACE rule that constrained compliance flexibility.[105] As EPA notes, there is no statutory language in section 111 that limits the flexibility of states in determining which measures will best achieve compliance with the emissions guideline. To the contrary, that flexibility is consistent with section 111's language, which focuses on the aim of achieving sufficient pollution reduction, not the manner in which that reduction is accomplished. Specifically, section 111(a)(1) provides that state plans are to include standards of performance for regulated facilities that "reflect[] the degree of emission limitation achievable through application of the best system of emission reduction."[106] In addition, section 116 of the Clean Air Act preserves the "right of any State . . . to adopt or enforce . . . any standard or limitation respecting emissions of air pollutants" as long as such standard or limitation is at least as stringent as one "in effect under an applicable implementation plan or under section 7411" of the statute.[107] Although there may be instances in which emissions averaging or trading potentially could run afoul of this structure (e.g., by enabling the creation of pollution "hot spots"), such a concern would not arise in the context of emissions guidelines that require limiting GHG emissions, such as carbon dioxide or methane.[108] Therefore, the States and Cities support EPA's change in interpretation as justified in this rulemaking.[109]

C. Remaining Useful Life and Other Factors

In establishing standards of performance for existing facilities, states are permitted under the statute to take into account the remaining useful life of a specific facility as well as other factors.[110] And in promulgating a federal plan for states that did not submit plans or had plan submittals disapproved, EPA is required to take remaining useful life and other factors into account in establishing standards of performance for specific facilities.[111] In our comments on the initial proposal, the States and Cities suggested that EPA provide guidance on how the remaining useful life criterion should be applied to the different types of oil and gas facilities.

In the Supplemental Proposal, EPA proposes several additional requirements to guide states that decide to take into account remaining useful life and other factors in establishing standards of performance for oil and gas facilities. The agency's overall approach and rationale are discussed in subsection 1 below, while the specific proposed revisions are discussed in subsection 2. Finally, subsection 3 sets forth our comments on EPA's treatment of state plans

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[105] 87 Fed. Reg. at 74,812.
[106] 42 U.S.C. § 7411(a)(1).
[107] *Id.* § 7416.
[108] *See Amer. Lung Ass'n*, 985 F.3d at 958.
[109] As EPA notes, it is also proposing to change the ACE rule interpretation in the context of its section 111(d) implementing regulations, which establish the default procedures and requirements for all state plans under section 111(d). 87 Fed. Reg. at 74,813. Many of the States and Cities intend to address this topic in their comments on that proposed rule as well.
[110] 42 U.S.C. § 7411(d)(1).
[111] *Id.* § 7411(d)(2).

that establish more stringent standards of performance than required under the emissions guideline.

1. Overview of EPA Approach and Rationale

Overall, the proposed changes to the remaining useful life and other factors provision stem from EPA's concerns that the current section 111(d) implementing regulations do not provide clear parameters for states on how and when they may establish a less stringent standard for a particular facility than the presumptive level in the emissions guideline.[112] Specifically, without a clear analytical framework for applying remaining useful life and other factors, the current provision could be used by states to set less stringent standards that would effectively undermine the overall presumptive level of stringency envisioned by EPA's BSER determination.[113] Furthermore, EPA's evaluation of whether each state plan is "satisfactory," including application of remaining useful life and other factors, must be generally consistent from one plan to another. Accordingly, if states do not have clear parameters on how to consider these factors, they face the risk of submitting plans that EPA may not be able to consistently approve as satisfactory.

To address these concerns about the current regulations, EPA's proposed revisions would tether the remaining useful life and other factors analysis to the statutory factors EPA considered in its BSER determination.[114] This change would enable states to adjudge whether the application of the BSER factors to a particular designated facility is fundamentally different than the EPA determinations made to support the BSER and presumptive level of stringency in the emissions guideline. Under this approach, the remaining useful life and other factors generally would be applicable only for a subset of sources for which implementing the BSER would impose unreasonable costs or not be feasible due to unusual circumstances that are not applicable to the broader source category that EPA considered when determining the BSER. EPA finds further legal support for this approach in variance procedures under other environmental statutes, such as the fundamentally different factors approach under the Clean Water Act.[115]

The States and Cities agree that changes to help guide states in applying remaining useful life and other factors would improve consistency in EPA evaluations, promote equity among states, and further section 111's pollution reduction aims. We offer comments on the specific aspects of EPA's proposed changes below.

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[112] 87 Fed. Reg. at 74,817–18. In parallel, as referenced in the supplemental proposed rule, EPA has proposed changes to the remaining useful life and other factors provisions of the implementing regulations. *See* 87 Fed. Reg. at 79,196–206. As noted above, many of the States and Cities will also be submitting comments on that proposed rule.
[113] 87 Fed. Reg at 74,818.
[114] *Id.*
[115] *Id.* at 74,819.

2. Specific Provisions

Consistent with the agency's proposed changes to its section 111(d) implementing regulations, EPA proposes in its emissions guideline for oil and gas facilities to revise the way in which states apply remaining useful life and other factors in establishing standards of performance. Those changes include or relate to: threshold requirements, source-specific BSER, contingency requirements, capital expenditures and retirement dates, and consideration of impacts on local communities.

- ***Threshold requirements for considering remaining useful life and other factors***. The current regulations contain certain threshold criteria that must be triggered for a state to establish a less stringent standard based on the remaining useful life of a facility (or other factors). While retaining the threshold requirements in the current regulations that refer to an unreasonable cost of control resulting from plant age, location, or basic process design or physical impossibility of installing necessary control equipment, EPA proposes to modify the current "catchall" third criterion to apply if a state demonstrates that there are other factors specific to the facility (or class of facilities) "that are fundamentally different from the factors considered in the establishment of the emission guidelines."[116] For example, if the state could demonstrate that the cost-per-ton of pollution reduction at a particular facility would be significantly higher than estimated by EPA in its BSER analysis, that facility may be evaluated for a less stringent standard. States would not be permitted to invoke the remaining useful life and other factors provision based on minor, non-fundamental differences.

  The States and Cities support these proposed revisions to the threshold requirements for applying remaining useful life and other factors. The "fundamentally different" language adds clarification on applying the other factors and is consistent with variance provisions in the Clean Water Act and other environmental laws.

- ***Source-specific BSER***. EPA is proposing several requirements that would apply for calculation of a standard of performance that incorporates remaining useful life and other factors, including a source-specific BSER for the designated facility.[117] The state plan submission would have to identify all control technologies available for the source and evaluate the BSER factors (cost, non-air quality health and environmental impacts, energy requirements, amount of reductions, and advancement of technology) for each technology. The standard would have to be in the same form (e.g., numerical rate-based emission standard) as the presumptive standard.

  The States and Cities support the source-specific BSER requirement. The BSER factors encompass all the information relevant to a state's determination of an appropriate

[116] *Id.* at 74,819.
[117] *Id*. at 74,821.

emission standard for a facility to which the remaining useful life or other factors could properly apply.

- ***Contingency requirements***. Where a state seeks to rely on a designated facility's operational conditions—such as the source's remaining useful life or restricted capacity—as a basis for setting a less stringent standard, EPA proposes to require enforceable conditions for that facility in the state plan to address the scenario where a source's operations change.[118] This requirement would address operating conditions such as operation times, operational frequency, process temperature or pressure, and other conditions that are subject to the discretion and control of the designated facility.[119]

  The States and Cities support imposing contingency requirements in instances where a less stringent standard is based on an operational constraint within a facility's control. As EPA notes, in the absence of an enforceable requirement, a subsequent (unforeseen) change in a facility's operations could result in foregone emission reductions and undermine the level of stringency in the emissions guideline.[120]

- ***Capital expenditures and retirement provisions***. EPA is proposing certain requirements regarding capital expenditures and retirement dates in scenarios where a state seeks to apply a less stringent standard on grounds that a designated facility will retire in the near future. First, the state plan must identify the source's retirement date and explain why this date qualifies for imposition of a less stringent standard, i.e., why the cost of control is unreasonable in relation to the retirement date.[121] A state would have to demonstrate unreasonable cost of control for each of the identified compliance options, not just one.[122] Second, EPA is proposing that the only cost factor that should be considered in this emissions guideline for oil and gas facilities is whether there is a significant capital investment required to design, purchase, and install equipment.[123] EPA reasons that a BSER based on compliance measures that do not require such upfront capital expenditures would have been demonstrated to have reasonable costs in EPA's analysis of the presumptive standards. Because controlling methane pollution would not require a significant capital investment for certain types of designated oil and gas facilities, under EPA's proposed approach a less stringent standard based on unreasonable cost would be available for the following types of designated facilities only: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps. Retiring facilities (except those retiring in six months or less) that qualify under the proposed revisions

[118] *Id.* at 74,821–22.
[119] *Id.* at 74,822.
[120] *Id.* at 74,821.
[121] *Id.* at 74,822.
[122] *Id.* at 74,823.
[123] *Id.*

would also need to have their retirement date included as a federally enforceable requirement and comply with a reasonably achievable source-specific BSER.

The States and Cities support the proposed requirements concerning retirement dates and capital expenditures. As set forth in our comment on the initial proposal, the inclusion of presumptive standards for many types of facilities in the emissions guideline likely lessens the instances in which a performance standard in a state plan would need to be relaxed compared to the guideline to account for a facility's remaining useful life or other site-specific factors. And the control of fugitive emissions from well sites and compressor stations through use of LDAR, for example, could be done throughout the remaining useful life of these sources without the need to install any retrofit technology. We suggest, however, that EPA should more expressly explain why it is proposing to limit the unreasonable cost criterion to the four types of oil and gas facilities cited above.

- ***Consideration of impacted communities***. For situations in which a state seeks to consider a facility's remaining useful life in establishing a performance standard less stringent than called for in the emissions guideline, EPA proposes to require that the state consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the facility.[124] These communities would be identified by the state as pertinent stakeholders under the proposed meaningful engagement requirements. EPA explains that it has authority under section 111(d)'s "other factors" language and section 111(d)(2)'s general requirement that state plans be "satisfactory" to impose this requirement.

  The States and Cities strongly support requiring states to consider impacts of a less stringent standard on communities located near the facility. Congress's inclusion of the "other factors" language indicates that additional factors other than remaining useful life could be relevant to determining the appropriate performance standard for individual facilities. Also, section 111(d)'s language directing that EPA "permit" states to consider remaining useful life indicates that the agency has some discretion regarding how states can apply remaining useful life, among other factors, in establishing performance standards. Given that the purpose of regulating stationary source pollution under section 111 is to address emissions that endanger public health and welfare, requiring that states take into account how excess pollution (above the level reflected in application of the BSER) may impact the health and welfare of local communities is consistent with the statutory design. Finally, EPA's oversight authority in ensuring that state plans do a "satisfactory" job of adopting standards that reflect the degree of emission reduction from applying the BSER provides additional support for requiring that potential harms from exceeding the emissions guideline be adequately considered.

[124] *Id.* at 74,824.

3. Authority to Apply More Stringent Standards as Part of State Plan

In the initial proposed rule, EPA took the position that it must approve section 111(d) state plans that are more stringent than the emissions guideline if the plan is otherwise in compliance with all applicable requirements.[125] In our comments, we agreed with EPA's view of the relevant statutory sections and its conclusion that EPA must approve a more stringent state plan that meets the criteria set forth in the emissions guidelines.

Similarly, in the Supplemental Proposal, EPA proposes that under section 111(d), consistent with authority reserved to states pursuant to section 116 of the Clean Air Act, states may consider other factors to include more stringent standards of performance in their state plans.[126] In reconsidering its previous interpretation in the ACE rule, EPA proposes to interpret that the statute authorizes EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by the emissions guideline.[127]

The States and Cities support EPA's interpretation in the Supplemental Proposal. As EPA explains, there is nothing in the language of section 111(d) suggesting that EPA has the authority to preclude states from determining that it is appropriate to regulate certain sources within their jurisdiction more strictly than otherwise required by federal requirements.[128] And the inclusion of the "other factors" language in section 111(d) demonstrates that Congress envisioned that states could consider additional circumstances—such as effects on local communities—in determining standards of performance for specific facilities.

D. Providing Measures That Implement and Enforce Such Standards

EPA is proposing to supplement the initial proposal by clarifying that states would be required to maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements, as described in the emissions guideline. The States and Cities support requiring that state plans maintain the same or equivalent monitoring, reporting, and recordkeeping requirements as set forth in the emissions guideline to ensure that facilities comply with their standards of performance.

E. Emissions Inventories

In the initial proposal, EPA sought comment on whether to supersede the requirement in the current section 111(d) implementing regulations that state plans contain emissions data on a source-specific or unit-specific level and replace that requirement with a different emissions

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[125] 86 Fed. Reg. at 63,251–52 (citing section 116 of the Clean Air Act and *Union Elec. Co. v. EPA*, 427 U.S. 246 (1976)).
[126] *Id.* at 74,825.
[127] EPA has proposed a similar interpretation in the context of its proposed section 111(d) implementing regulations. *See* 87 Fed. Reg. at 79,204.
[128] 87 Fed. Reg. at 74,826.

inventory requirement that seeks to represent the same general type of information but allows states to utilize existing inventories and emissions data, such as EPA's Greenhouse Gas Reporting Program.[129] In our comments, the States and Cities suggested that EPA allow states to utilize existing inventories and emissions data—even if that data might not fully align with the designated facilities in the emissions guidelines—provided that the data submitted by states is rigorous and comprehensive enough to accurately capture emissions from the oil and natural gas industry.

In the Supplemental Proposal, based on comments received on the initial proposal from several states (including Colorado), EPA proposes to supersede the emissions inventory requirements of 40 CFR § 60.25a(a) in this emissions guideline, so that state plans are not required to include an inventory and emissions data.[130] Under this approach, states would be allowed to leverage existing emission inventories and emissions data, even if that data may not be fully aligned with the designated facilities in the emissions guideline.

As discussed in our comments on the initial proposal, the States and Cities support this aspect of the guidelines.

F. Meaningful Engagement

In its initial proposal, EPA proposed to require states to perform early outreach and meaningful engagement with overburdened and underserved communities during the development process of state plans to comply with the emissions guideline for oil and gas facilities.[131] In the States' and Cities' comments, we agreed on the importance of meaningful engagement of all stakeholders in the development of state plans, and with EPA's efforts to ensure that these communities play an important role in the process, including through setting forth some minimum criteria for participation. We urged EPA to take existing state practices into account in light of the fact that some states have developed robust environmental justice programs that include public participation. We also asked EPA to provide some additional information on its proposed meaningful engagement criteria.

EPA now proposes to require that states provide, in their plan submittals, a list of the pertinent stakeholders and a summary of engagement conducted and of the stakeholder input provided.[132] EPA explains that given the public health and welfare objectives of section 111(d) in regulating specific existing sources, it is reasonable to require meaningful engagement as part of the state plan development participation process. In its parallel proposed rule to revise the section 111(d) implementing regulations, EPA has included definitions for "meaningful engagement" and "pertinent stakeholders." Meaningful engagement would include:

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[129] 86 Fed. Reg. at 63,251.
[130] 87 Fed. Reg. at 74,827.
[131] 86 Fed. Reg. at 63,254.
[132] 87 Fed. Reg. at 74,829.

> the timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate in favor of certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the state plan.[133]

Pertinent stakeholders would "include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision."[134] The agency is also soliciting comments on examples or models of meaningful engagement by states, including best practices and challenges.

As discussed in our comments on the initial proposal, the States and Cities support making meaningful engagement with impacted communities and other stakeholders a state plan requirement. Such a requirement is consistent with the statutory design. Section 111(d) provides that EPA regulations are to follow a procedure similar to the development of state plans under section 110 of the Clean Air Act, which expressly calls for "reasonable notice and public hearings."[135] The proposed meaningful engagement and pertinent stakeholder definitions and requirements would help to implement the reasonable notice and public hearing language set forth in the statute by adding parameters designed to ensure that the input of affected communities and businesses is taken into account. In recent comments several of the States and Cities submitted to the Internal Revenue Service, we offered some thoughts on approaches to facilitate the participation of disadvantaged communities, such as expanding opportunities for participation, providing multilingual services, and targeted outreach.[136] In addition, for examples of meaningful engagement that our States and Cities already use, we refer EPA to comments submitted by our respective state agencies on the initial proposal and on this supplemental one.

G. Timing of State Plan Submissions and Compliance Times

With respect to the timing for submitting state plans, EPA did not initially propose a specific deadline, but instead solicited comment on a reasonable deadline in light of facts and circumstances that are unique to the oil and natural gas industry.[137] In our comments, the States and Cities suggested a timeline in which state plans would be due within 12 months after EPA's

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[133] 87 Fed. Reg. at 79,191 (proposed 40 C.F.R. § 60.21a(k)).
[134] *Id.* (proposed 40 C.F.R. § 60.21a(l).
[135] 42 U.S.C. §§ 7411(d)(1), 7410(a)(1).
[136] *See* Att. 34, Comments of the Massachusetts Attorney General, et al. on Requests for Comments on Implementation Guidance for the Inflation Reduction Act (Dec. 1, 2022) at 7, available at https://www.mass.gov/doc/multistate-inflation-reduction-act-comments/download.
[137] 86 Fed. Reg. at 63,255.

promulgation of the final guideline (with the ability to seek additional time depending on a state's specific statutory requirements for creation and adoption of state plans).

In the Supplemental Proposal, EPA is proposing that states be required to submit their plans within 18 months after publication of the final emissions guideline.[138] This proposed period is a bit longer than the default 15-month deadline in the proposed rule to revise section 111(d) implementing guidelines. EPA argues that 18 months is reasonable here based on its evaluation of the need to balance the complexity of the oil and gas emissions guideline and the need to mitigate climate change and protect human health. EPA also undertook an analysis of the time required for states to submit previous plans to regulate existing facilities pursuant to section 111(d) and section 129 emission guidelines and found that state plans typically took longer than 12 months to submit.[139] On the other hand, EPA concluded that a 36-month time period (the deadline included in the ACE rule, vacated by the D.C. Circuit, and not subsequently addressed by the Supreme Court) was unnecessary for states to develop their plans to regulate existing oil and gas facilities and also unjustified in light of the fact that rapid methane reductions are critical to reducing the near-term disruption of the climate system.[140]

Although we suggested a 12-month time frame for state plan submittal in our comments on the initial proposal, in light of EPA's additional analysis in the Supplemental Proposal summarized above, the States and Cities recognize that a longer period may be needed. We urge EPA to establish the shortest time frame necessary to accommodate the administrative procedures of the states charged with implementing the guideline.

With respect to source compliance, EPA initially proposed that state plans include schedules requiring compliance with the standards of performance as expeditiously as practicable, but no later than two years following the state plan submittal deadline.[141] The States and Cities advocated for earlier compliance deadlines for designated facilities for which EPA has proposed LDAR as the presumptive non-numerical standard (e.g., for well sites, compressor stations, and gas plants). Specifically, we urged that EPA should require in its final rule that the compliance deadline for presumptive standards based on LDAR be no longer than one year.

Now, EPA is proposing that state plans impose a compliance timeline on designated facilities to require final compliance as expeditiously as practicable, but no later than three years following the state plan submittal deadline.[142] EPA believes that establishing a uniform three-year compliance deadline would simplify compliance and ease the burden on large and small business owners and operators that need to develop and implement approaches to meet their compliance obligations for a large number of designated facilities.

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[138] 87 Fed. Reg. at 74,831.
[139] *Id.* at 74,832.
[140] *Id.* at 74,833–34.
[141] 86 Fed. Reg. at 63,256.
[142] 87 Fed. Reg. at 74,836.

As discussed in our comments on the initial proposal, even a two-year deadline is excessive for facilities that need only adopt LDAR practices to comply. New York's regulations, for example, were finalized in March 2022 and required compliance with LDAR by January 1, 2023.[143] EPA has failed to justify why such a lengthy compliance period would be necessary for these types of facilities. Although the agency cites to possible time delays for pneumatic controller compliance stemming from an anticipated high demand for specialized control equipment,[144] EPA has not explained why a two-year (much less a three-year) compliance period for LDAR is necessary. In addition, although EPA cites to the critical need to promptly reduce methane emissions when discussing the appropriate deadline for state plan submittals, the agency failed to consider this important factor in the context of the appropriate deadline for facility compliance. The desire to simplify compliance and ease the burden on industry operators is not a valid basis for this time frame under the statute and not warranted by these circumstances.

V. EPA's Cost-Benefit Analysis Supports the Supplemental Proposal

EPA expects that the net economic benefits of the 2021 Proposal and the Supplemental Proposal will outweigh the costs, taking into consideration the avoided social costs imposed by GHG emissions and the industry's ability to sell the natural gas that will be captured by the new controls. The undersigned support EPA's use of the interim Social Cost of Methane (SCM) established in the Interagency Working Group on Social Cost of Greenhouse Gases' (IWG) recently published Technical Support Document (2021 TSD)[145] in evaluating the costs and benefits of the Supplemental Proposal.[146] Although the IWG is currently in the process of reviewing comments on how to improve and update the social cost of greenhouse gases (SC-GHG), including the SCM,[147] for now the interim value for SCM established in the 2021 TSD represents the best available estimate of the long-term cost to society of increasing methane emissions now.[148] Moreover, the SC-GHG does not dictate the outcome of any specific agency rulemaking, including this one. Here, EPA considers the SCM in evaluating the costs and benefits of the Supplemental Proposal,[149] but nowhere suggests that those values were used to determine the BSER for the oil and natural gas sector, or that they will be determinative of its

[143] *See* 6 NYCRR § 203-7.
[144] 87 Fed. Reg. at 74,835.
[145] EPA-HQ-OAR-2021-0317-0005, Interagency Working Group on Social Cost of Greenhouse Gases, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimate Under Executive Order 13,990* (Feb. 2021) (hereinafter, "2021 TSD").
[146] EPA-HQ-OAR-2021-0317-1566, Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (hereinafter, "RIA") at 65.
[147] *See Notice of Availability and Request for Comment on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13,990*," 86 Fed. Reg. 24,669, at 24,670 (May 7, 2021).
[148] *See* RIA, *supra* n.146, at 65–66.
[149] RIA at 3.2.

ultimate decision.[150] The SCM is simply one additional tool for monetizing some of the benefits of a regulation that would otherwise be non-monetized, not a thumb on the scale of agency cost-benefit analyses

A. EPA's Cost-Benefit Analysis Appropriately Relies on the Interim Value for the Social Cost of Methane Established by the Interagency Working Group, Which Represents the Best Available Science for Assigning a Monetary Value to the Impact of Greenhouse Gases

As EPA appropriately describes, the interim value for the SCM in the 2021 TSD is based on the SCM established in a 2016 TSD, which was reached following a comprehensive, multi-year process of peer review and public comment. The IWG comprises economic and scientific experts from across the federal government.[151] Estimates of the SCM are based on the best available, peer-reviewed literature and economic models.[152] These estimates were developed using the three leading climate models that link greenhouse gas emissions to physical changes and economic damages; each model has been published and extensively reviewed in the scientific literature.[153] The IWG has thoroughly and transparently discussed the models, inputs, and assumptions used, and has acknowledged the uncertainties of climate science.[154] The U.S. Government Accountability Office reviewed the IWG's process and concluded that the IWG:

> (1) Used consensus-based decision making; (2) relied largely on existing academic literature and models, including technical assistance from outside resources; and (3) took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available.[155]

Courts have also accepted, and at times required, the use of the SC-GHG in valuing climate-change related impacts. The Seventh Circuit upheld the Department of Energy's (DOE) use of the SC-GHG in evaluating the benefits of its refrigeration efficiency standards.[156] The Court concluded that DOE's use of the SC-GHG to conduct an assessment of the rule's environmental benefits was authorized by the Energy Policy and Conservation Act (EPCA),[157]

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[150] 87 Fed. Reg. at 74,843.
[151] 2021 TSD, *supra* n.145, at 1, 10–12.
[152] *Id.* at 10–12.
[153] *Id.*
[154] *Id.* at 26–32.
[155] Att. 35, U.S. Gov't Accountability Off., *Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates*, at 8 (July 2014), *available at* https://www.gao.gov/assets/gao-14-663.pdf.
[156] *Zero Zone, Inc. v. U.S. Dep't of Energy*, 832 F.3d 654, 678-80 (7th Cir. 2016).
[157] 49 U.S.C. §§ 32901–19

which provided for consideration of "the need for national energy . . . conservation."[158] The Court also turned aside a variety of objections to the development and reliability of the SC-GHG, concluding that DOE had appropriately responded to those objections and determined that the SC-GHG could be used to assess environmental benefits.[159]

Moreover, courts have rejected agency action for failure to consider the SC-GHG. For example, in *Center for Biological Diversity v. National Highway Traffic Safety Administration*, the Ninth Circuit held that the National Highway Traffic Safety Administration (NHTSA) had acted arbitrarily and capriciously when it established vehicle efficiency standards under EPCA, without monetizing the benefits of greenhouse gas emissions reductions.[160] The Court rejected NHTSA's argument that the value of reducing greenhouse gas emissions was "too uncertain" to quantify.[161] The Court stressed that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[162] Moreover, the Court observed that NHTSA had monetized the value of *other* uncertain benefits, including the reduction of criteria pollutants, crashes, and increases in energy security.[163]

Other courts have held that, if an agency quantifies the economic benefits of an action that could increase GHGs, it must also employ the SC-GHG to quantify the costs of the increased emissions.[164] These court decisions recognize that the SC-GHG is a reliable and scientifically validated approach to monetizing climate change impacts that should be incorporated into federal decision-making. It is therefore appropriate for EPA to employ the SCM in evaluating the benefits of the proposed rule.

B. EPA's Cost-Benefit Analysis Appropriately Relies on a Social Cost of Methane that Takes Into Account a Global Perspective on Climate Change Impacts

The undersigned agree with EPA's recognition that the SCM must take into account global, not just domestic, emissions.[165] As far back as 2008, EPA recognized that:

> GHGs are global pollutants. Economic principles suggest that the full costs to society of emissions should be considered in order to identify the policy that maximizes the net benefits to society, i.e.,

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[158] *Zero Zone, Inc.*, 832 F.3d at 677.
[159] *Id.*
[160] 538 F.3d 1172, 1198–1203 (9th Cir. 2008).
[161] *Id.* at 1200.
[162] *Id.*
[163] *Id.* at 1202.
[164] *See Montana Envt'l Info. Ctr. v. U.S. Office of Surface Mining*, 274 F.Supp.3d. 1074, 1095–99 (D. Mt. 2017); *High County Conservation Advocates v. U.S. Forest Serv.*, 52 F.Supp.3d 1174, 1189–92 (D. Col. 2014).
[165] RIA, *supra* n.146, at 68–69.

> achieves an efficient outcome. Estimates of global benefits capture more of the full value to society than domestic estimates and can therefore help guide policies towards higher global net benefits for GHG reductions. Furthermore, international effects of climate change may also affect domestic benefits directly and indirectly to the extent U.S. citizens value international impacts (e.g., for tourism reasons, concerns for the existence of ecosystems, and/or concern for others); U.S. international interests are affected (e.g., risks to U.S. national security, or the U.S. economy from potential disruptions in other nations); and/or domestic mitigation decisions affect the level of mitigation and emissions changes in general in other countries (i.e., the benefits realized in the U.S. will depend on emissions changes in the U.S. and internationally). The economics literature also suggests that policies based on direct domestic benefits will result in little appreciable reduction in global GHGs.[166]

The consideration of global impacts is also fully within the authority of federal agencies. In *Zero Zone*, the Seventh Circuit specifically upheld DOE's consideration of global – just national – benefits, accepting DOE's explanation that "climate change involves a global externality, meaning that carbon released in the United States affects the climate of the entire world."[167]

In fact, ignoring global climate change impacts would be arbitrary and capricious. In *California v. Bernhardt*, the Northern District of California held that the Bureau of Land Management (BLM) had erred in evaluating only the domestic costs of increases in greenhouse gas emissions from BLM's repeal of regulations to reduce waste at natural gas wells.[168] The Court noted that "focusing solely on domestic effects has been soundly rejected by economists as improper and unsupported by science."[169] The Court concluded that BLM could not "construct a model that confirms a preordained outcome while ignoring a model that reflects the best science available."[170]

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[166] *Regulating Greenhouse Gas Emissions Under the Clean Air Act*, 73 Fed. Reg. 44,354, 44,415–16 (July 30, 2018) (internal citations and footnotes omitted).
[167] *Zero Zone*, 832 F.3d at 679.
[168] 472 F.Supp.3d 574, 608–14 (N.D. Cal. 2020), *appeal pending* Docket Nos. 20-16794, 20-16801 (9th Cir.).
[169] *Id.* at 613.
[170] *Id.* at 614.

C. EPA's Sensitivity Analysis Recognizes Some of the Limitations of the Interim Value for the Social Cost of Methane that Underestimate the Costs of Climate Change, But It Should Engage in a Fuller Discussion of Those Limitations

EPA is correct to recognize that the interim value for SCM established in the 2021 TSD likely underestimates the true cost of climate change impacts, both in its use of discount rates and in the assumptions made by the underlying climate models.[171] The undersigned States and Cities urge EPA to more fully evaluate these uncertainties by running additional evaluations with lower discount rates and by expanding its discussion of non-quantified impacts from climate change.

In our comments on the 2021 Proposal, we applauded the fact that EPA recognized that the interim value for SCM established in the 2021 TSD likely underestimates the true cost of climate change impacts, both in its use of discount rates and in the assumptions made by the underlying climate models.[172] We urged EPA to more fully evaluate these uncertainties by running additional evaluations with lower discount rates and by expanding its discussion of non-quantified impacts from climate change. We revisit these two issues below.

Previously, the States urged EPA to use lower discount rates (below 3%) in order to account for the long-term, intergenerational impacts of climate change. As the IWG now recognizes, "the 3 percent discount rate used by the IWG to develop its range of discount rates is likely an overestimate of the appropriate discount rate."[173] Since 2008, federal agencies have recognized that:

> There are reasons to consider even lower discount rates in discounting the costs of benefits of policy that affect climate change. First, changes in GHG emissions—both increases and reductions—are essentially long-run investments in changes in climate and the potential impacts from climate change. When considering climate change investments, they should be compared to similar alternative investments (via the discount rate). Investments in climate change are investments in infrastructure and technologies associated with mitigation; however, they yield returns in terms of avoided impacts over a period of one hundred years and longer. Furthermore, there is a potential for significant impacts from climate change, where the exact timing and magnitude of these impacts are unknown. These factors imply a highly uncertain investment environment that spans multiple generations.

[171] RIA, *supra* n.146, at 69–70.
[172] *Id*.
[173] 2021 TSD, *supra* n.145, at 17.

> When there are important benefits or costs that affect multiple generations of the population, EPA and OMB allow for low but positive discount rates (e.g., 0.5-3% noted by U.S. EPA, 1-3% by OMB).[174]

Indeed, recent studies show support for a long-term discount rate of "no higher than 2 percent."[175] We thus applaud EPA's proposal, in its External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (Draft Report), to use dynamic discount rates with three near-term target rates of 1.5%, 2%, and 2.5%.[176] We believe that the version with a near-term target rate of 1.5% is the most appropriate, because it incorporates a near-zero pure rate of time preference.[177] The Draft Report notes that "Ramsey (1928), for example, argued that it is 'ethically indefensible' to apply a positive pure rate of time preference to discount values across generations."[178] Individual human beings' preference for short-term over long-term benefits in the course of their own lifetimes should not be relevant to evaluating multigenerational impacts. We recommend that EPA identify as the most accurate SC-GHG estimates those estimates which include a pure rate of time preference of zero or near zero.

We also urge EPA to highlight the fact that the SC-GHG does not reflect significant damage categories that have not yet been monetized. The Draft Report acknowledges the existence of omitted damages but ignores, or only vaguely alludes to, some of the most important omitted damage categories, and does not conduct the kind of analysis of omitted damages called for by OMB Circular A-4. The Supplemental Proposal does not acknowledge the existence of

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[174] 73 Fed. Reg. at 44,354.
[175] *See* Att. 23, Tamma Carleton, et al., *Updating the United States Government's Social Cost of Carbon*, Energy Policy Institute at the University of Chicago, Working Paper No. 2021-04, at 23 (Jan. 2021), *available at* https://epic.uchicago.edu/wp-content/uploads/2021/01/BFI_WP_202104_Final.pdf; *accord* Expert Report, *The Use of the Social Cost of Carbon in the Federal Proposal "Safer Affordable Fuel-Efficiency (SAFE) Vehicles Rule,"* (attached to comments of California Air Resources Board on EPA Docket No. EPA-HQ-OAR-2017-0355), Maximilian Auffhammer, Oct. 24, 2018, at 12; Att. 36, Council of Economic Advisers, *Discounting for Public Policy: Theory and Recent Evidence on the Merits of Updating the Discount Rate*, Issue Brief, at 3 (Jan. 2017), *available at* https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf.
[176] EPA-HQ-OAR-2021-0317-1549, EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances (Sept. 2022) (hereinafter, "Draft Report") at 60 (Table 2.4.2).
[177] *Id.* at 54 ("The pure rate of time preference, ρ, is the rate at which the representative agent discounts utility in future periods due to a preference for utility sooner rather than later. The elasticity of marginal utility with respect to consumption, η, defines the rate at which the well-being from an additional dollar of consumption declines as the level of consumption increases.").
[178] *Id.* at 52.

omitted damages at all, stating without qualification, "[i]n principle, SC–CH4 includes the value of *all* climate change impacts."[179] As stated in our comments on the 2021 Proposal, economists reviewing the SC-GHG models have extensively analyzed areas of damages that are not quantified or are otherwise underestimated.[180] As New York's evaluation of appropriate SC-GHG values observed, "[t]he [climate models] only partially account for, or omit, many significant impacts of climate change that are difficult to quantify or monetize, including ecosystems, increased fire risk, the spread of pests and pathogens, mass extinctions, large-scale migration, increased conflict, slower economic growth, and potential catastrophic impacts."[181] We previously highlighted several areas of unquantified damages that are particularly important to the States. We will reiterate our discission of two of those: (1) health impacts from wildfires, and (2) loss of culturally and historically significant assets. The first of these is only briefly referenced in the Draft Report; the second is ignored.

The climate models underlying the SC-GHG values do not account for impacts from wildfires, which include both health and economic effects.[182] Each year, millions of Americans suffer through lengthy episodes of extremely unhealthy air due to wildfires, as the wildfire season becomes lengthier and more destructive due to climate change. Indeed, the *Fourth National Climate Assessment* highlighted health risks from wildfires as a major consequence of climate change, stating that "[e]xposure to wildfire smoke increases the risk of respiratory disease and mortality … Wildfires are projected to become the principal driver of summertime $PM_{2.5}$ concentrations, offsetting even large reductions in emissions of $PM_{2.5}$ precursors."[183] In December 2021, wildfires destroyed approximately one thousand homes and businesses in Boulder County, Colorado—where the usual wildfire season is May to September—because of a combination of changed climate conditions including a summer drought, a historic lack of

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[179] 87 Fed. Reg. at 74,843 (italics added).
[180] *See, e.g.*, Att. 24, Ruth DeFries, et al., *The missing economic risks in assessments of climate change impacts* (Sept. 2019), *available at* https://www.lse.ac.uk/granthaminstitute/wp-content/uploads/2019/09/The-missing-economic-risks-in-assessments-of-climate-change-impacts-2.pdf; Att. 25*,* Institute for Policy Integrity, *A Lower Bound: Why the Social Cost of Carbon Does Not Capture Critical Climate Damages and What that Means for Policymakers* (Feb. 2019), *available at* https://policyintegrity.org/files/publications/Lower_Bound_Issue_Brief.pdf; Att. 26, Peter Howard, *Omitted Damages: What's Missing from the Social Cost of Carbon*, at 30 (Mar. 13, 2014).
[181] Att. 37, Resources for the Future, *Estimating the Value of Carbon: Two Approaches*, at 3 (Oct. 2020, revised April 2021), *available at* https://media.rff.org/documents/RFF_NYSERDA_Valuing_Carbon_Synthesis_Memo.pdf
[182] *See Lower Bound*, *supra* n.180, at 5; *Omitted Damages*, *supra* n.180, at 20, 30.
[183] *Fourth National Climate Assessment, supra* n.18, at 521–22.

December snowfall, and extreme winds.[184] It is reasonable to expect that any effort to account for SC-GHG would include such a high-profile effect of climate change.

The Draft Report mentions the omission of wildfires, stating that "the estimated health damages in GIVE and DSCIM only include temperature- and SLR-related mortality, and exclude other sources of mortality impacts (e.g., climate mediated changes in storms, wildfire, flooding, air pollution), and morbidity impacts (e.g., infectious diseases, malnutrition, allergies)."[185] Wildfire also appears as a subset of the "partially accounted for" category of "[m]ortality and morbidity from extreme weather events (e.g., storms, wildfire, flooding), and sea level rise." [186] But the Draft Report's discussion of wildfires and other "omitted damages" falls far short of the kind of analysis called for in OMB circular A-4. Specifically, the Circular states:

> It will not always be possible to express in monetary units all of the important benefits and costs…If the non-quantified benefits and costs are likely to be important, you should carry out a 'threshold' analysis to evaluate their significance...[Y]ou should indicate, where possible, which non-quantified effects are most important and why.

The Draft Report *lists* wildfire damages and other damage categories as unquantified or partially quantified. But it does not "evaluate their significance," nor does it "indicate … which non-quantified effects are most important and why." We believe that conducting the kind of analysis called for in OMB Circular A-4 would greatly enhance the informative value of all future discussions of the SC-GHG.[187]

As we previously explained, another area of unquantified damages identified by the National Academy of Sciences is the "loss of goods and services that are not traded in markets and so cannot be valued using market prices," such as "loss of cultural heritage, historical

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[184] Att. 38, Jason Samenow, Jacob Feuerstein, and Becky Bolinger, *How Extreme Climate Conditions Fueled Unprecedented Colorado Fire*, Wash. Post (Dec. 31, 2021), https://www.washingtonpost.com/weather/2021/12/31/colorado-fires-climate-weather-drought/; *see also* Att. 39 Tynin Fries, *List of homes and businesses destroyed in the Marshall fire*, The Denver Post (Jan. 1, 2022), https://www.denverpost.com/2022/01/01/marshall-fire-homes-destroyed-list-addresses-businesses/
[185] Draft Report, *supra* n.176, at 71.
[186] *Id*. at 73.
[187] The Draft Report dedicates significant space to one category of omitted damages—damages from ocean acidification. *Id*. at 75–76. Clearly then, EPA considers this category important. However, because this is the only category of omitted damages that is discussed extensively, it is unclear whether EPA considers it the *only* significant omitted damage category. If so, EPA should clarify this point, after undertaking the OMB Circular A-4 analysis.

monuments, and favored landscapes."[188] The Union of Concerned Scientists has identified many historic sites and landmarks at risk from climate change:

- Boston historic districts and Faneuil Hall, MA
- The Statue of Liberty and Ellis Island, NY and NJ
- Harriet Tubman National Monument, MD
- Historic Annapolis, MD
- Historic Jamestown, VA
- Fort Monroe National Monument, VA
- NASA's Coastal Facilities, FL and TX
- Cape Hatteras Lighthouse, NC
- Historic Charleston, SC
- Historic St. Augustine, FL
- Mesa Verde National Park, CO
- Bandelier National Monument, NM
- Cesar Chavez National Monument, CA.[189]

The loss of these unique sites would exceed the monetary value of the land upon which they are located. Landmarks such as these are not the only culturally and historically significant resources at risk. As the Regulatory Impact Analysis for the Supplemental Proposal recognizes:

> Indigenous communities possess unique vulnerabilities to climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change.[190]

EPA should disclose that the SCM does not take into account impacts to historically significant locations or to culturally significant resources; should consider those impacts in its

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[188] Att. 40, Nat'l Academy of Sciences, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, at 152 (2017).
[189] Att. 28, Union of Concerned Scientists, *National Landmarks at Risk: How Rising Seas, Floods, and Wildfires Are Threatening the United States' Most Cherished Historic Sites*, at 4–32, 36–40, 44 (2014).
[190] RIA at 110-111 (italics added); *see also* Carson Viles, *Tribal Climate Change Profile: First Foods and Climate Change* (December 2011) ("Because of the vital role that first foods play in the physical, mental, and spiritual health of native communities, impacts from climate change on first foods may negatively affect tribal culture and livelihood.") *available at* http://www7.nau.edu/itep/main/tcc/docs/tribes/tribes_FirstFoodsCC.pdf

evaluation of the benefits of the Supplemental Proposal; and should acknowledge that these impacts are not accounted for in the SCM and other variants of the SC-GHG. We believe that an EPA "significance" analysis, as called for by OMB Circular A-4, would reveal that the ongoing loss of culturally and historically significant resources will be one of the most important non-quantified damage categories.

For these reasons, we urge EPA to acknowledge and discuss significant "omitted damages," including damages from wildfire, and damages to culturally and historically important resources, whenever EPA refers to the SC-GHG in rulemaking.

VI. CONCLUSION

In sum, the States and Cities strongly support EPA's Supplemental Proposal. Further, as detailed in these comments, the State and Cities request that EPA strengthen certain elements of the Supplemental Proposal before issuing a final rule.

Sincerely,

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<u>Exhibit B</u>

The Colorado Local Government Coalition's Comments on "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 Fed. Reg. 74,702 (Dec. 6, 2022), EPA-HQ-OAR-2021-0317-2408

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

	)	
Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review	)))))))	**<u>Docket No. EPA-HQ-OAR-2021-0317</u>** *Via regulations.gov* *February 13, 2023*

We submit these comments on behalf of:

THE COLORADO LOCAL GOVERNMENT COALITION OF CITY OF AURORA, BOULDER COUNTY; CITY AND COUNTY OF BROOMFIELD; COMMERCE CITY, THE CITY OF LAFAYETTE; THE CITY OF LONGMONT; THE TOWN OF ERIE, AND COLORADO COMMUNITIES FOR CLIMATE ACTION, CONSISTING OF: ADAMS COUNTY, THE CITY OF ASPEN, THE TOWN OF AVON, THE TOWN OF BASALT, THE CITY OF BOULDER, BOULDER COUNTY, THE TOWN OF BRECKENRIDGE, THE CITY AND COUNTY OF BROOMFIELD, THE TOWN OF CARBONDALE, CLEAR CREEK COUNTY, THE TOWN OF CRESTED BUTTE, THE TOWN OF DILLON, THE CITY OF DURANGO, EAGLE COUNTY, THE CITY OF EDGEWATER, THE TOWN OF ERIE, THE CITY OF FORT COLLINS, THE TOWN OF FRISCO, GILPIN COUNTY, THE CITY OF GLENWOOD SPRINGS, THE CITY OF GOLDEN, THE CITY OF LAFAYETTE, LAKE COUNTY, LARIMER COUNTY, THE CITY OF LONGMONT, THE CITY OF LOUISVILLE, THE TOWN OF LYONS, THE TOWN OF MOUNTAIN VILLAGE, THE TOWN OF NEDERLAND, THE CITY OF NORTHGLENN, OURAY COUNTY, PITKIN COUNTY, THE TOWN OF RIDGWAY, ROUTT COUNTY, THE TOWN OF SALIDA, SAN MIGUEL COUNTY, THE TOWN OF SNOWMASS VILLAGE, SUMMIT COUNTY, THE TOWN OF SUPERIOR, THE TOWN OF TELLURIDE, THE TOWN OF VAIL, AND THE CITY OF WHEAT RIDGE

I. Introduction

The above-referenced local governments, participating together as the Colorado Local Government Coalition ("Colorado LGC" or "LGC") submit the following comments on EPA's proposal to reduce greenhouse gasses ("GHGs") and other harmful air pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act ("CAA" or the "Act"), *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (Dec. 6, 2022) (the "Proposal" or "NSPS Rule").[1] Rigorous and comprehensive national measures to

[1] These comments revise the signature for Boulder County but are otherwise exactly the same as comments submitted to the docket earlier on Feb. 13, 2023.

curb pollution from this industry are critically necessary to address climate change and regional ozone pollution caused by venting, flaring and leaks.

A subset of the current members of the Colorado LGC[2] submitted comments on the rule EPA proposed in November of 2021, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 86 Fed. Reg. 63,110 (Nov. 15, 2021) ("Nov. 2021 Proposal"). Those comments discussed the impacts of climate change on Coloradans and expressed support for strong national rules to curb methane pollution. We recommended EPA eliminate emissions from natural-gas powered pneumatic controllers based on rules adopted in Colorado and New Mexico; require annual leak detection and repair ("LDAR") for wells with the potential to emit ("PTE") less than 3 tons per year ("tpy") of methane; prohibit the routine flaring of associated gas based on rules adopted in Colorado and New Mexico; allow the use of advanced monitoring, including participation by the local community, to find and fix leaks more quickly; require quarterly LDAR inspections for idle wells and annual inspections for plugged wells; and require capture or control of other sources of venting, such as pigging, equipment blowdowns, and hydrocarbon liquid transfers. Our 2021 comments set forth the basis for our recommendations, which in many cases stemmed from our own experience as permitters and regulators of oil and gas sources and the experience of leading states, such as Colorado and New Mexico, in regulating oil and gas emissions.

We strongly support many of the provisions in the current proposal as consistent with our prior recommendations and leading state standards. In particular, we commend EPA on the following aspects of its proposal which reflect our 2021 comments: the zero-emission standard for new and existing gas-powered pneumatic controllers; the use of an equipment-based approach to dictate the frequency of LDAR inspections in lieu of the former PTE based approach; the new super-emitter response program that allows third parties (including state or local governments) to conduct inspections for large, i.e., "super-emitter" leaks; the inclusion of idle wells in LDAR and inspection requirements up to the end of a well's life; and the requirement of operators to submit a well closure plan for plugged wells to EPA.

Our comments below include a brief discussion of the need for national rules to reduce ozone precursor emissions and protect disproportionately impacted communities. We support the proposed super-emitter response program as a very useful tool for accomplishing these goals. We provide recommendations for where we believe EPA can and should be more protective of human health and the environment. Specifically, as discussed below, we recommend EPA:

- Ban the routine practice of venting or flaring associated gas from oil wells while providing narrow, specific exemptions for temporary flaring.
- Reduce venting from well completions by requiring capture or control of emissions during the initial flowback stage of well completions and eliminating the technical infeasibility exemption in the separation flowback stage.

[2] Commerce City, the City of Aurora, and the Town of Erie were not part of the 2021 LGC but are part of the current coalition.

- Require annual optical gas imaging inspections for small well sites and wellhead only sites.
- Require operators submit a well closure plan for abandoned wells within 30 days of well approval, rather than within 30 days of well closure, and require review and resubmission of the plan, as necessary, upon transfer of ownership of wells.

II. The Importance of Strong Rules to Reduce Ozone Precursors

The LGC is deeply concerned with oil and gas related air pollution. The Denver metropolitan area has a long history of nonattainment with the various ozone National Ambient Air Quality Standards ("NAAQS"). Studies have identified elevated levels of atmospheric volatile organic compounds ("VOCs") in Colorado's North Front Range. These studies indicate the potential for significant ozone production from these emissions.[3] Denver ranks among the top 10 U.S. metropolitan areas for number of asthma attacks and is the eighth most ozone-polluted city in the United States.[4] The Denver Metro/North Front Range ("DM/NFR") ozone nonattainment area accounts for almost 58% of the state's population, with over 3.3 million people residing in the area. Despite numerous attempts to reduce ozone precursor emissions from the oil and gas sector since 2004, air quality in the DM/NFR is currently classified as Severe nonattainment for the 2008 NAAQS.

Oil and gas emissions are also contributing to ozone pollution outside the DM/NFR. Ozone monitors outside the DM/NFR are approaching the 2015 NAAQS. According to Colorado's September 30, 2022, ozone update, the design values (i.e., the three-year average of the fourth maximum recorded 8-hour concentration) for 2020-2022 were violating or approaching the 2015 NAAQS at several locations outside the nonattainment area.[5]

Ozone, a regional pollutant, affects most of Colorado's population, including many of our most vulnerable residents. Colorado counties with significant oil and gas development are plagued with such high levels of ozone that they received an "F" grade for ozone from the American Lung Association in 2021, as well as prior years. Several of these areas have a strong association with pediatric and adult asthma and cardiovascular disease and are home to people of color and people meeting the U.S. Census estimates of poverty.[6] Furthermore, climate change worsens

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[3] G. Pétron, *et al*., Journal of Geophysical Research: Atmospheres, Vol. 117, No. D4, "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study" (Feb. 21, 2012), at p. 17-18, *available at* https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2011JD016360; J.B. Gilman, *et al*., Environmental Science & Technology, Vol. 47, "Source Signature of Volatile Organic Compounds from Oil and Natural Gas Operations in Northeastern Colorado" (Jan. 14, 2013), *available at* https://pubs.acs.org/doi/abs/10.1021/es304119a; R.F. Swarthout, *et al.*, Journal of Geophysical Research: Atmospheres, Vol. 118, No. 18, "Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources" (Aug. 12, 2013), at p. 10,635-36, *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.

[4] L. Fleischman, *et al.*, Clean Air Task Force, "Gasping for Breath: An analysis of the health effects from ozone pollution from the oil and gas industry" (Aug. 2016), at p. 10, *available at* http://www.catf.us/wp-content/uploads/2018/10/CATF_Pub_GaspingForBreath.pdf.

[5] Colorado Air Pollution Control Division, "Summary Table: 2022 Running O3" (updated Sept. 30, 2022), *available at* https://www.colorado.gov/airquality/html_resources/ozone_summary_table.pdf.

[6] American Lung Association: State of the Air, "Report Card: Colorado" (2022), *available at* https://www.lung.org/research/sota/city-rankings/states/colorado.

ozone, in a feedback that is felt most strongly in areas that are home to higher percentages of Hispanic/Latino residents, children living in limited-income households, and residents with health conditions and/or lacking health insurance.[7] Despite ozone forecasts and guidance issued by local governments and state air agencies to help residents avoid ozone exposure, disproportionately impacted community residents are more likely to work outdoors during high-ozone times and to have fewer occupational protections from ambient air pollution.

Local governments in Colorado, including Boulder County, the City and County of Broomfield, the City of Longmont and the Town of Erie have funded or conducted their own air quality studies in their communities to assess local impacts.[8] The results of those studies support the need for increased regulation of the oil and gas industry to improve ozone conditions and reduce greenhouse gas emissions.

Strong national rules, such as those proposed by EPA and with the additional improvements we suggest, will help protect Colorado's most vulnerable communities from harmful air pollution associated with ozone pollution and climate change while also helping Colorado come into attainment with the ozone NAAQS.

III. Super Emitter Response Program

We support the proposed "super-emitter response program." This program will help protect local communities from potentially dangerous emissions by allowing third parties to remotely monitor oil and gas facilities for large leaks. Specifically, as proposed the program contains the following elements:

- Third parties, who have been approved by EPA, may remotely monitor oil and gas facilities for large leaks. EPA proposes a leak threshold of 100 kg/hr.[9]
- Third parties may use remote sensing equipment including aircraft, mobile monitoring platforms, or satellites to detect super-emitters.[10]
- Upon detection of a super-emitter, third parties must notify the owner or operator of the oil and gas facility. The notification must provide detailed information including the location of the emissions, a description of the technology and sampling protocols used to identify emissions, and the date and time of detection and confirmation after data analysis that a super-emitter event was present.
- Third parties must notify EPA and any delegated state entity of the results of inspections. EPA must make such reports available to the public.
- Owners and operators who receive a notification of detection of a super-emitter event must take swift action to confirm if a super-emitter event occurred at one of their sites, and if so, to remedy it. Specifically, an operator must conduct a root cause analysis to identify the cause of the event. This could include conducting a

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[7] LGC_PHS_EX-002, J.L. Crooks, *et al.*, Journal of Exposure Science & Environmental Epidemiology, "The ozone climate penalty, NAAQS attainment, and health equity along the Colorado Front Range" (Sept. 10, 2021), at p. 551, *available at* https://www.nature.com/articles/s41370-021-00375-9.
[8] https://bouldair.com/
[9] 87 Fed. Reg. 74702, 74,749 (Dec. 6, 2022).
[10] *Id*.

> follow-up investigation with an IR camera and repairing the source of the leak (e.g., closing a thief hatch on a controlled tank). If the investigation determines that the cause of the event is something other than a malfunction or abnormal emissions, the operator must identify the source of the event in their report to EPA. For example, a maintenance activity where venting is allowed, could be the source of the event. Operators must commence the root cause analysis within 5 calendar days of receipt of the third-party report and must conclude any corrective actions within 10 days of notification, unless additional time is necessary, in which case operators have until thirty days from receipt of the notification.[11] Operators must submit a report to EPA within 15 days of completion of the root cause analysis and corrective action describing the source of emissions, the corrective actions taken, and the compliance status of the affected facility.

The super-emitter program is intended to be a backstop to the LDAR program in that it can help ensure that large leaks or unintentional venting caused by malfunctions or abnormal operations are quickly detected and corrected.

EPA notes that facilities in compliance with the standards it proposes here should not be the source of significant super-emitters because EPA's proposal removes, or requires frequent monitoring, of the largest sources of leaks: controlled tanks; flares; gas-powered pneumatic controllers; and fugitive emissions components.[12] This is because EPA is requiring operators conduct quarterly inspections of controlled tanks and control devices such as flares, is phasing out existing gas-powered pneumatic controllers and requiring new pneumatic controllers to be zero bleed, and requiring frequent inspections of fugitive emissions components. We agree with EPA that the proposed requirements for pneumatic controllers and inspection requirements for control devices and fugitive emissions components located at large well sites will help eliminate or reduce super emitters from these sources. Were EPA to adopt our recommendation to require annual OGI inspections at small well sites and wellhead only sites, we would also agree with EPA that such requirements would help reduce super emitters from fugitive emissions components located at these facilities.

The super-emitter program will have important benefits for communities affected by air pollution from the oil and natural gas sector including communities disproportionately impacted by air pollution. The program will help reduce community exposure to harmful air toxics that are co-emitted with methane and VOCs. We strongly support EPA's proposal to make publicly available third-party inspection reports so that communities are aware of any potential exposure to harmful emissions.

IV. Opportunities for Improvement

A. Associated Gas Flaring

EPA's Proposed Rule would require operators to capture associated gas from the separator using one of the following options: (1) routing to a sales line; (2) using gas for an onsite fuel source;

[11] 87 Fed. Reg. at 74,750-51.
[12] 87 Fed. Reg. at 74,748.

(3) using the gas for another useful purpose that a purchased fuel or raw material would serve; or (4) reinjection into a well or injection into another well for enhanced oil recovery.[13] EPA proposes to allow flaring only where the operator certifies that it is not feasible to employ one of these options due to technical or safety reasons.[14] This demonstration would need to address the specifics regarding the lack of availability to a sales line, including efforts by the operators to get access to a sales line or to facilitate alternative offsite transport and use of associated gas and show why all potential beneficial uses are not feasible.[15] EPA proposes to require the initial demonstration include "a detailed analysis documenting and certifying the technical or safety reasons" as to why implementing the best system of emission reduction or any of the abatement alternatives is not feasible or safe.[16] EPA proposes operators obtain a certification by a professional engineer or other qualified individual when submitting an initial technical infeasibility demonstration.[17] Subsequently, an operator's annual report must include either a statement that no change has been made at the site since the original certification that would impact the operator's ability to comply versus flare, or if a change has been made since the original certification, a recertification of infeasibility or a statement indicating that compliance can be achieved and a description of how compliance will be achieved.[18] Operators must also include the start date, time, and duration of each instance of venting.[19]

We reiterate the comments we previously submitted to EPA on its initial proposal which called for a nation-wide ban on the wasteful and unnecessary practice of routine flaring. By routine flaring we mean ongoing, continuous flaring in the absence of a method for capturing and selling, putting to beneficial use, or storing associated gas.[20] Leading state examples and the commitments made by multiple operators demonstrate eliminating routine flaring is feasible and cost effective.

As our prior comments made clear, Colorado and New Mexico have largely banned this pernicious practice and we urge EPA to do the same. Colorado's rule provides: "[V]enting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, *are prohibited*."[21] Similarly, New Mexico's rule provides: "[V]enting or flaring of natural gas during drilling, completion, or production operations that constitutes waste as defined in 19.15.2 NMAC *is prohibited*. The operator has a general duty to maximize the recovery of natural gas by minimizing the waste of natural gas through venting and flaring. During drilling, completion and production operations, the operator may vent or flare natural gas only as authorized [through

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[13] 87 Fed. Reg. at 74,779.
[14] *Id*.
[15] 87 Fed. Reg. at 74,780.
[16] 40 C.F.R. 60.5377b(b)(1).
[17] 87 Fed. Reg. at 74,779-74,780.
[18] 40 C.F.R. § 60.5420b(b)(4)(ii)(B).
[19] 87 Fed. Reg. at 74,780
[20] *See e.g.*, definition of routine flaring as flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market. The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#8.
[21] 2 Colo. Code Regs. § 404-1-903.

specific regulations]."[22] Alaska has also largely banned this practice, allowing operators to flare only during specific, narrowly conditioned exceptions.[23]

Numerous operators have committed to eliminate routine flaring as part of the World Bank's Zero Routine Flaring by 2030 Initiative. To date, 54 oil companies and 34 governments have endorsed the "Zero Routine Flaring by 2030" Initiative. Based on satellite estimates and publicly reported flaring data, together the endorsers represent around 60% of global flaring.[24] Exxon Mobile recently announced a commitment to end routine flaring while also expressing support for regulations banning this wasteful practice. [25]

Eliminating routine flaring is a cost-effective way to curb methane emissions. Joint environmental commenters submitted a detailed analysis to EPA in 2021 documenting that the four abatement options EPA proposes here are cost effective.[26] Specifically:

- The Rystad report shows that connecting wells to gathering line infrastructure is not only highly cost-effective but actually profitable for operators, with an average net negative cost of $3.10 per thousand cubic feet (mcf) and $162 per MT of methane flaring avoided.[27]
- Rystad estimates that on average, on-site use of gas nets a profit of $8.60/mcf and $449 per MT of methane flaring avoided.[28]
- Rystad's report finds that on average, CNG trucking will cost operators $1.8/kcf, or $94 per MT of methane flaring avoided.[29] EPA views CNG trucking as falling into the "another useful purpose" category.[30]
- Reinjection costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/mcf, and $177 per MT of methane flaring avoided.[31]

Importantly, the costs of the abatement options are well below EPA's cost-effectiveness threshold. In the November 2021 Proposal and the 2022 Supplemental Proposal, EPA proposes to find that cost-effectiveness values up to $1,970/ton of methane reduction are reasonable for controls identified as BSER.[32]

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[22] N.M. Code R. § 19.15.27.8(A).
[23] 20 Alaska Admin. Code § 25.235(d)(1)-(6) (for example, flaring due to emergencies and safety authorizations for planned lease operations are limited to a maximum of one-hour per event. *See* subsections (1), (2))).
[24] World Bank website, Zero Routine Flaring by 2030 (ZRF) Initiative, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030.
[25] Exxon has stopped routine flaring of natural gas from production in the top U.S. shale basin and will press for stronger regulations for rivals to do the same. Reuters, *Exxon Halts Routine Gas Flaring in The Permian, Wants Others to Follow* (Jan. 24, 2023). https://www.nasdaq.com/articles/exclusive-exxon-halts-routine-gas-flaring-in-the-permian-wants-others-to-follow
[26] Env't Def. Fund et al., *Comments on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, Dkt. No. EPA-HQ-OAR-2021-0317-0844 (Jan. 31, 2022) (Hereinafter "Joint Environmental Comments").
[27] Rystad Energy, Cost of Flaring Abatement, Slide 11 (Jan. 31, 2022) (Hereinafter "Rystad"), Ex. W to Joint Environmental Comments.
[28] *Id*.
[29] *Id*.
[30] 87 Fed. Reg. at 74,779.
[31] Rystad, Slide 11.
[32] 87 Fed. Reg. at 74,718.

We urge EPA to revise its proposal to prohibit routine flaring by requiring operators use one of the four abatement methods EPA here proposes. EPA should allow for flaring only during explicit, narrowly tailored, and time-limited, exemptions. Doing so will more clearly and unequivocally prohibit pollution stemming from routine flaring, as well as enhance the enforceability of the rule. Our comments below flesh out our concerns with the proposed approach and recommends an alternative framework for reducing associated gas venting and flaring. These concerns would be addressed if EPA adopted our recommendation to prohibit flaring other than in specific, time-limited, and narrowly tailored, exemptions.

1. The Technical Infeasibility Exemption is Vague and Broad

We have concerns with allowing operators to flare based on a demonstration that one of the four abatement options is "technically infeasible." EPA has not proposed a definition for "technically infeasible." As such, this exemption could apply to a large universe of circumstances identified by operators as falling within this broad exemption. An option that may be technically feasible for one operator may not be deemed feasible by another. From an operator's standpoint, the line between technical infeasibility and economic feasibility may be fluid. Without a clear definition of technical infeasibility, we are concerned that this broad exemption could lead to abuse. At a minimum, it is likely to be inconsistently applied by operators and by regulators. Specifically, and as discussed further below, Colorado promulgated rules to remove the "technical infeasibility" exemption in EPA's reduced emission completion requirements.[33]

Another concern with the technical infeasibility exemption is that it applies equally to both temporary and routine flaring. As the rules implemented in Colorado and New Mexico demonstrate, routine flaring is rarely, if ever, necessary. Both states require operators to demonstrate they will capture, not flare or vent, associated gas during production, at the time operators submit an application for a permit to drill. Specifically, Colorado requires an operator to "commit to connecting to a gathering system . . . or submit a gas capture plan" prior to commencing production. The gas capture plan must describe the operator's "plan for connecting their facilities to a natural gas gathering system or otherwise putting gas to beneficial use."[34] New Mexico requires operators certify that it will be able to connect a new well to a gas gathering system with sufficient capacity to transport all of the gas the operator anticipates the well will produce at the time the operator submits an application for a permit to drill.[35] If an operator cannot make such certification, an operator must either: (1) shut in the well until it can make the necessary certification; or (2) submit a venting and flaring plan that chooses one or more alternative beneficial uses until a gas gathering system is available, including power generation on lease, power generation for grid, compression on lease, liquids removal on lease, reinjection, fuel cell production, or other beneficial use approved by the state.[36] These common-sense requirements reflect the fact that operators have complete control over the decision regarding where and when to drill a new well and when to complete or put such a well into

[33] 5 Colo. Code Regs. § 1001-9-D-VI.D.1.a.
[34] 2 Colo. Code Regs. § 404-1-903.e.
[35] N.M. Code R. § 19.15.27.9.D.(4).
[36] N.M. Code R. §19.15.27.9.D.(5).

production.[37] As such, operators of new wells can address both timing and infrastructure capacity challenges.

Routine flaring from existing wells is equally avoidable or preventable. Operators of existing wells may currently not be connected to gathering lines or may lose their connection due to no fault of their own. In the event of the former, other cost-effective options are available including converting the associated gas to CNG, using it to replace a different fuel source, such as diesel for onsite fuel purposes, converting the gas to electricity, injecting it or reinjecting it.[38] Inclusion of a limited exception for temporary flaring during an upset condition can address an operator's need to flare temporarily in the event an operator loses its connection to a gathering line, for example due to a disruption to the availability of the line caused by events outside its control. Prudent operators should have a plan and necessary equipment in place to address the possibility that they will lose access to takeaway capacity, as this is a known risk associated with producing oil and associated gas. As EPA's proposal recognizes, alternative technologies exist to recover and put to beneficial use associated gas and at least one, if not more, of these alternatives is likely available to operators who lose connection to a gathering line. In addition, operators can temporarily shut-in wells in the event of loss of takeaway capacity while arranging for alternative ways to recover and put to beneficial use associated gas.

As discussed below, Colorado and New Mexico rules do not allow for routine flaring in the event that an operator loses connection to a gathering line.

2. The Technical Infeasibility Exemption Presents an Enforcement Challenge

As proposed, the technical infeasibility exemption places a significant compliance monitoring burden on EPA, or states with delegated air quality programs such as Colorado. While an operator's certified demonstration must be signed and certified as to its truth, accuracy and completeness, there is no requirement that EPA review and approve this demonstration prior to an operator flaring. Rather, operators must retain records of the certified demonstration and provide it to EPA as part of annual reporting. This raises the possibility that flaring will occur in the absence of a truthful, accurate, complete or otherwise adequate demonstration. In order for EPA to identify any problems with the certified demonstration, EPA must review the operator's certified demonstration – this review will necessarily occur after an operator has flared, and even routinely flared for potentially a considerable amount of time. This opens the door to extended periods of flaring and pollution in violation of the rules.

3. Exemptions that Allow for Short-term Flaring

We urge EPA to abandon the broad, unclear technical infeasibility exemption and instead delineate those instances in the rule where temporary flaring is allowed, subject to reasonable, limitations. Doing so is consistent with the approach in Colorado and New Mexico.

[37] Joint Environmental Comments at 187, 194.
[38] Joint Environmental Comments at 187.

a. Upset Condition

During an upset condition operators may need to flare or vent for a limited period. Notably, upset conditions are conditions outside of the control of an operator that can interrupt the ability of the operator to comply with the proposed standard. An example of an upset condition is temporary loss of connection to, or ability to route gas to, a gathering system. EPA has determined that interruptions of an operator's ability to route gas to a gathering system constitute a technical or safety reason that can justify flaring and is taking comment on requirements to address this circumstance.[39] We agree that interruptions to an operator's connection to a gathering system can result in the need for operators to flare on a temporary basis. However, routine flaring is avoidable and should not be permitted during these circumstances.

Both Colorado and New Mexico allow operators to flare or vent gas for a short period of time during upset conditions or emergencies which include temporary unavailability of access to a gathering line.

The Colorado rules provide a concise, clear definition of upset condition combined with a limit on the amount of time an operator may flare or vent during such circumstances. Colorado allows operators to vent or flare for up to 24 cumulative hours during an upset condition while New Mexico allows operators to vent or flare for up to 8 hours during an emergency. Loss of a connection to a pipeline qualifies as an upset condition under the Colorado rules and an emergency under the New Mexico rules.

Colorado's definition of an Upset Condition is "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction." This definition does not include "an operator's negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance."[40] Colorado limits venting and flaring to a period necessary to address the upset, not to exceed 24 cumulative hours and requires operators maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each upset condition.[41] This definition includes "sudden unplanned lack of pipeline capacity."[42] Accordingly, Colorado allows operators to vent or flare associated gas in the event that disruptions to a gathering system interrupt the ability of an operator to route associated gas to a sales line, but only up to 24 cumulative hours.[43]

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[39] 87 Fed. Reg. at 74,780.
[40] COGCC SBP, 800/900/1200 Rule Series, p.76, *available at* https://drive.google.com/drive/u/0/folders/1kTZUgXmhVpOy4gEZ2tSOYVDDvYXupzvA
[41] 2 Colo. Code Regs. § 404-1-903(d)(1)(A).
[42] COGCC SBP, 800/900/1200 Rule Series, p.76.
[43] Colorado also allows operators to request approval to flare for a longer period of time, up to 12 months, in the event of loss of access to a gathering line due to unforeseen circumstances outside of the operator's control. An operator may only request approval once, however. To avail itself of this option, an operator must request permission to flare within 30 days of loss of access to a gathering line, and cannot flare unless approval is granted. This request must be accompanied by detailed information demonstrating why the well cannot be connected to infrastructure, when the well will be connected to infrastructure, options for using the gas, including to generate electricity, gas processing to recover natural gas liquids, or other options for using the gas, an estimate of the volume and content of the gas to be flared and a gas analysis. 2 Colo. Code Regs. § 404-1-903.d.(3).

New Mexico similarly allows for temporary venting or flaring during an emergency. An emergency means "a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment" other than in certain exceptions. One such exception is "venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, an unscheduled maintenance, or a malfunction of a natural gas gathering system."[44] In other words, an upstream operator may vent or flare during a temporary, infrequent, and unavoidable event involving loss of connection to a sales line provided the midstream operator notifies the producer of the disruption to the operator of the sales line. However, an upstream operator cannot vent longer than 8 hours in this circumstance.[45]
We recognize that there may be instances when an operator loses connection to a sales line for reasons other than during an emergency of upset condition, such as where the midstream operator ceases to operate the gathering line or where the demand for the gathering line exceeds its capacity. We do not believe flaring or venting should be permitted in these circumstances. These are foreseeable risks that prudent operators can and should plan for. As discussed above, prudent operators should have equipment in place to utilize associated gas for other beneficial purposes (e.g., compression for conversion of natural gas to CNG) in the event of a loss of takeaway capacity. New Mexico does not allow operators to vent or flare during non-emergency losses of takeaway capacity.[46] An operator's failure to limit production when the production rate exceeds the capacity of the related equipment or natural gas gathering system, or exceeds the sales contract volume of the natural gas, do not constitute emergencies during which an operator may vent or flare.[47] Colorado contains a limited exception that allows operators to request permission to flare in the event of loss of connection to a sales line, but this exception is only available once to an operator, and to qualify for it an operator must demonstrate there are no alternative options available to recover the gas.[48] As discussed above, we do not believe such an exception is warranted with proper planning.

We recommend EPA limit flaring (or venting) during an upset condition not to exceed 24 cumulative hours per R.903.d.(1)(A). This would apply in those instances where a disruption to a gathering system or other event causes an interruption to an operator's ability to route the gas to a sales line.

b. During Pipeline, Equipment or Facilities Commissioning

Another circumstance that may give rise to an operator's need to vent or flare on a temporary basis is during the commissioning of pipelines, equipment, or facilities. New Mexico allows operators to vent or flare temporarily during pipeline equipment or facilities commissioning.[49] New Mexico limits waste during this activity to "only for as long as necessary to purge introduced impurities."[50] When starting up operation of new equipment, there is often water (used to hydro test) or solids (from stimulation flowback) that need to be purged from the

[44] N.M. Code R. §19.15.27.7.H.
[45] *Id*. at § 19.15.27.7.H.(4).
[46] *Id*. at § 19.15.27.7.H.(4).
[47] *Id*.
[48] 2 Colo. Code Regs. § 404-1-903.d.(3).
[49] N.M. Code R. § 19.15.27.8.D.(4)(m).
[50] *Id*.

equipment or pipeline. This can only be done be releasing this gas with untreatable impurities to atmospheric tanks which allows for the small volumes of gas to also be released until a stable hydrocarbon stream is achieved. While New Mexico does not limit the amount of time an operator may need to vent or flare during this exception, operators have an incentive to limit venting or flaring to a minimum as the sooner they connect the well to a gathering line, the sooner they are able to route the gas to sales.

c. Where Gas Does Not Meet Pipeline Specifications

Operators may also need to flare temporarily where an operator is connected to a sales line, but natural gas does not meet pipeline specifications, and where the other three compliance options are also unavailable.[51] This occurs where impurities such as nitrogen are present in the associated gas and thus the gas cannot safely be sent to the sales line. New Mexico requires the operator take specific steps to limit flaring during this circumstance as follows: Operators must analyze gas samples twice a week to determine if pipeline specifications have been achieved; must route gas into gathering pipelines when pipeline specifications are met and must provide pipeline specs and NG analyses to division upon request.[52] New Mexico does not include a specific time-limit for this exemption. However, per the example above, operators have a profit incentive to limit flaring or venting.

d. Active and Required Maintenance

A fourth exception is during active or required maintenance. Both Colorado and New Mexico allow for temporary venting and flaring during maintenance activities. Colorado specifies that maintenance must be active and required "to clarify that while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited."[53] Colorado requires operators use best management practices to minimize venting during maintenance and repair activity.
New Mexico similarly allows venting or flaring during repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance.[54]

We recommend EPA allow flaring and venting during active and required maintenance activities, provided not otherwise prohibited by EPA or state rules.

e. Production Evaluation and Production Tests

Colorado and New Mexico allow for temporary flaring during production tests and production evaluations. Colorado defines a production test to mean "a test for determination of a reservoir's ability to produce economic quantities of oil or gas."[55] Colorado defines a production evaluation as "an evaluation of production potential for determination of requirements for infrastructure

[51] N.M. Code R. § 19.15.27.8.D.(4)(l).
[52] *Id*.
[53] COGCC SBP, 800/900/1200 Rule Series, p. 84.
[54] N.M. Code R. § 19.15.27.8
[55] 2 Colo. Code Regs. § 404-1-100-15.

capacity and equipment sizing."[56] Colorado allows venting or flaring during both of these events, but only subject to pre-approval from the Director. If the operator has obtained approval, the rules permit venting or flaring up to a period not to exceed 60 days.[57] New Mexico limits venting or flaring during a production test for a period not to exceed 24 hours absent approval for a longer test period.[58]

We recommend EPA allow venting or flaring during this exception yet limit the duration of 24 hours as Colorado has done.

f. Bradenhead Monitoring and Packer Leakage Tests

Limited venting or flaring may also occur when operators conduct monitoring activities to inspect downhole well integrity. Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.[59] Per the Statement of Basis and Purpose for Colorado's rule, bradenhead monitoring activities should be limited to30 minutes.[60] New Mexico allows operators to conduct packer leakage tests, which is another form of downhole monitoring.[61] In both instances, venting and flaring should be limited to 30 minutes.

B. Well Completions

1. EPA's Proposal

EPA is proposing to maintain the same standards for reduced emission completions (RECs) contained in OOOO and OOOOa.

Current rules require owners and operators of hydraulically fractured oil and gas wells to either capture or combust emissions during the separation phase of completions. Specifically, owners and operators of non-exploratory and non-delineation wells (i.e., Subcategory 1 wells) must capture gas unless it is technically infeasible to do so, in which case such operators may combust gas.[62] Owners and operators of Subcategory 2 wells (i.e., exploratory, delineation and low-pressure wells) are allowed to combust gas using a completion combustion device provided the device has a continuous pilot flame.[63] Where combustion is allowed, operators may vent rather than combust, if combustion would present demonstrable safety hazards or if high heat may negatively impact tundra, permafrost, or waterways.[64]

Current rules do not require operators control or capture gas during the initial flowback stage.[65] Specifically during the initial flowback stage, operators of Subcategory 1 wells must route emissions to a storage vessel or completion vessel (such as a frac tank, lined pit, or other vessel)

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[56] 2 Colo. Code Regs. § 404-1-100-14.
[57] 2 Colo. Code Regs. § 404-1-903.d.(1)(C).
[58] N.M. Code R. §19.15.27.8.D.(4)(k).
[59] N.M. Code R. §19.15.27.8.D.(4).(i).
[60] COGCC SBP, 800/900/1200 Rule Series, p.86.
[61] N.M. Code R. §19.15.27.8.D.(4).(j).
[62] 86 Fed. Reg. at 63,120.
[63] 40 C.F.R. § 60.5375a(f)(3).
[64] *Id.* at § 60.5375a(a)(3)
[65] 40 C.F.R. § 60.5375a(a)(1)(i).

and separator. The operator is required "to have (and use) a separator onsite during the entire flowback period."[66] Notably, there is no requirement that an operator route gas to a control device or capture the gas. Owners and operators of Subcategory 2 wells may also route initial flowback to a separator instead of a combustion device, but only when the separator is available onsite and ready to be put into use "during the entirety of the flowback period,"[67] which includes the initial flowback phase.[68] If an owner or operator uses a separator, any gas in the flowback prior to the time the separator is able to function is "not subject to control under this section."[69]

2. LGC Recommendations

State rules provide templates for EPA to require additional cost-effective pollution reductions from completions. We have several suggestions: (1) require capture or control during the initial flowback stage; (2) remove the technical infeasibility exemption in the separation flowback stage; and (3) extend the REC requirements to conventional wells.

a. Require Control During Initial Flowback

We urge EPA to follow the example set by Colorado and New Mexico, which require control of venting during initial flowback. Colorado Air Quality Control Commission requires operators route flowback to enclosed flowback vessels after drill-out, and route emissions from flowback vessels to a device that achieves "a hydrocarbon control efficiency of at least 95%" or to a combustion device with "a design destruction efficiency of at least 98% for hydrocarbons."[70] Colorado Oil and Gas Conservation Commission rules further require that operators "enclose all [F]lowback vessels..." and adhere to the Air Quality Control Commission rules requiring the use of enclosed and controlled flowback vessels.[71]

New Mexico similarly requires operators "collect and control emissions from each flowback vessel..." and route emissions to a control device that achieves a hydrocarbon control efficiency of at least 95%.[72] Operators must ensure that the control device "operates as a closed vent system...and that unburnt gas is not directly vented to the atmosphere."[73]

As part of the development of the Air Quality Control Commission rule, the Colorado Department of Public Health and the Environment ("CDPHE") conducted a cost-benefit analysis and found its completion requirements were incredibly cost effective, even assuming a worst-case scenario. To estimate the costs of its rule, Colorado assumed operators needed 10 to 15 500 bbl flowback vessels at a multi-well production facility. CDPHE assumed new storage vessels would cost $30,500 and used storage vessels would cost between $7,000 and $19,000; $1,000 in one-time costs; and $500 in annual operation and maintenance costs, assuming a 15-year lifespan

[66] 87 Fed. Reg. at 74,710.
[67] 87 Fed. Reg. at 74,710.
[68] 86 Fed. Reg. at 63,160 (citing 81 Fed. Reg. 35,934) (June 3, 2016).
[69] 87 Fed. Reg. at 74,710.
[70] 5 Colo. Code Regs. § 1001-9-D-VI.D.1.a.
[71] 2 Colo. Code Regs. § 404-1-903.c.(1).
[72] N.M. Code R. § 20.5.20.127.B.(1).
[73] N.M. Code R. § 20.5.20.127.B.(1)(2).

for flowback tanks. Colorado found its annualized cost per flowback tank would be $4,830 and, assuming an average of 12 flowback tanks, the annualized costs per wellsite are $57,958.[74]

b. Remove the Technical Infeasibility Exemption

We recommend EPA remove the technical infeasibility exception for the separation flowback stage for Subcategory 1 wells and only allow for combustion with prior approval, as Colorado has done.[75] As discussed above, broad, undefined technical infeasibility exemptions open the door to abuse and present enforcement challenges. Neither New Mexico nor Colorado includes a technical infeasibility exemption in its completion rules.[76] New Mexico requires operators capture and route natural gas from separation equipment to a flowline or collection system or use the gas on-site.[77] New Mexico permits flaring only if necessary for safety[78] or temporarily if natural gas does not meet gathering pipeline quality specifications.[79] Colorado similarly only permits flaring with pre-approval[80] or if necessary to ensure safety during an upset condition.[81] Safety flaring during an upset condition is limited to 24 hours.[82]

c. Extend RECs to Conventional Wells

Lastly, we recommend that EPA extend its reduced emission completion requirements to non-hydraulically fractured wells, as is the case in Colorado[83] and New Mexico.[84] Per the Statement and Basis for Colorado's rules "the Commission intends for its reduced emission completion standards to apply to all wells, regardless of whether they are hydraulically fractured."[85] New Mexico's rules similarly apply to all wells.[86] EPA gives no reason for exempting non-hydraulically fractured wells from controlling emissions during completions.

C. LDAR

1. EPA's Proposal

The EPA has proposed different inspection programs depending on the size and type of equipment at well sites and centralized production facilities. Specifically, the type of monitoring (e.g., optical gas imaging ("OGI") or audio, visual, and olfactory inspections ("AVO")) and the

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[74] CDPHE, Air Quality Control Commission, Cost Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7, p. 23 (September 4, 2020), *available at* https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment_5.pdf.
[75] 5 Colo. Code Regs. § 1001-9-D-II.H.3.f.
[76] 2 Colo. Code Regs. § 404-1-903.c.(1).
[77] N.M. Code R. § 19.15.27.8.C.(2)
[78] *Id*. at § 19.15.27.8.C.(2)(b).
[79] *Id*. at § 19.15.27.8.C.(3).
[80] 2 Colo. Code Regs. § 404-1-903.c.(3)(A) (allowing flaring if approved on gas capture plan); *Id*. at 903.c.(3)(B) (allowing flaring if approved by Director and accompanied by justification for need to flare, plans to capture the gas, and estimate of anticipated flaring amount and duration).
[81] *Id*. at 903.c.(3)(C).
[82] *Id*.
[83] *Id*. at 903.c.(1).
[84] N.M. Code R. § 19.15.27.8.C.
[85] COGCC SBP, 800/900/1200 Rule Series, at p. 81.
[86] N.M. Code R. § 19.15.27.8.C.

frequency of inspections depends on the complexity of the site and the type of equipment present: more frequent inspections are required at complex sites with failure-prone equipment.

EPA proposes to require quarterly OGI inspections and bimonthly AVO inspections at well sites and centralized production facilities with major production and processing equipment. This includes: (1) one or more controlled storage vessels; (2) one or more control devices; (3) one or more natural gas-driven pneumatic controllers or pumps; and (4) two or more other major production and processing equipment.[87] EPA notes that these sites contain leak-prone equipment that can result in very large leaks, i.e., super-emitters.[88]

EPA proposes only AVO inspections at small well sites and single wellhead only sites. Small well sites are single wellhead well sites that do not contain any controlled storage vessels, control devices, gas-powered pneumatic controllers or pumps and include only one other piece of major production and processing equipment such as a separator, uncontrolled storage vessel, compressor or glycol dehydrator, or any affected or designated facility.[89] EPA estimates that approximately 12% of well sites nationwide meet this definition.[90] Surface casing valves and thief hatches on uncontrolled storage vessels are the most likely emissions sources at these well sites.[91] EPA notes that AVO is a reliable method for identifying such leaks and thus proposes quarterly AVO inspections for small well sites.[92] Single wellhead only well sites are well sites that contain one or more wellheads and no major production and processing equipment.[93] EPA finds that the most likely cause of a leak at a single wellhead only well site would be an open valve that allows venting from the wellhead. This is based on the results of a recent U.S. DOE marginal well study.[94] EPA proposes only AVO (i.e., quarterly AVO) requirements for these well sites based on its belief that OGI cameras are not necessary to identify venting from well heads.[95]

EPA proposes semi-annual OGI inspections and quarterly AVO inspections at multi-wellhead only sites. These are wellhead only sites with two or more wellheads. EPA finds that these sites can have large leaks from the same equipment present at single-wellhead sites (e.g., surface casing valves) which are identifiable with AVO, but also will have smaller leaks from piping and connections that are not identifiable with AVO.[96] Thus, EPA proposes semi-annual OGI inspections and quarterly AVO inspections at multi-wellhead only sites.

2. LGC Recommendations

We support EPA's proposed definition of the affected facility as the collection of fugitive emissions components located at a well site or centralized production facility with no

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[87] 87 Fed. Reg. at 74,723.
[88] 87 Fed. Reg. at 74,735.
[89] 87 Fed. Reg. at 74,723.
[90] *Id*.
[91] *Id*.
[92] *Id*.
[93] 87 Fed. Reg. at 74,723.
[94] 87 Fed. Reg. at 74,729.
[95] *Id*.
[96] 87 Fed. Reg. at 74,732.

exemptions. This is an improvement over the 2021 proposal which exempted low-PTE well sites from LDAR. However, we have concerns with the proposed AVO-only requirements for small well sites and single wellhead only sites. As demonstrated by our prior comments, small well sites can have leaks.[97] In addition, we do not share EPA's conviction that AVO is an effective method for identifying leaks.

State rules demonstrate the feasibility of requiring annual inspections at well sites with low emissions or the potential for emissions, a group that likely overlaps considerably with EPA's single wellhead only and small well sites categories. We recommend that EPA require annual OGI for single wellhead only and small well sites, based on rules adopted by Colorado and New Mexico. While we do appreciate the proposed AVO inspections, OGI methods can detect leaks that a human may not be able to detect. AVO inspections, in contrast to OGI inspections, rely on a person's senses of smell, hearing and sight to achieve maximum emissions reductions. Such senses may not be as reliable as instruments. Moreover, EPA may require operators retain video footage demonstrating that OGI inspections in fact occurred and documenting the results of those inspections. The same is not true for AVO inspections. Absent a way to document reliably that an operator, or more likely a contractor, conducted a thorough AVO inspection, we fear this requirement will be abused and will not lead to the emissions reductions EPA expects.

Colorado and New Mexico require instrument-based inspections for small wells, and New Mexico requires instrument-based inspections for wellhead only facilities. Colorado requires all well production facilities that commence operation on or after May 1, 2022, to conduct monthly instrument-based inspections, regardless of size or emissions potential.[98] The only exceptions to this is for facilities which are not home to leak-prone equipment (i.e., facilities without storage tanks, natural gas-fired reciprocating internal combustion engines and gas-powered pneumatic devices)[99] or those that contain robust monitoring for leak prone equipment (i.e., those that install an automatic pressure management and pilot light system on controlled storage tanks).[100] Such facilities must conduct instrument-inspections semi-annually or annually, depending on emissions potential.[101] Well production facilities that commenced operation before May 1, 2022 must conduct at least annual instrument-based inspections.[102]

New Mexico requires at least annual OGI inspections of ***all*** well sites, including wellhead only well sites.[103] New Mexico's proposal has the support of the local community and national environmental groups.[104]

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[97] LGC Comments, EPA's Proposal to Reduce Greenhouse Gasses and other Pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act, p. 10-15 (Jan. 31, 2022).
[98] 5 Colo. Code Regs. § 1001-9-D-II.E.4.e.(ii)
[99] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(i).
[100] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(ii)
[101] 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.
[102] 5 Colo. Code Regs. § 1001-9-D-II.E.4, Table 5.
[103] N.M. Code R. § 20.2.50.116.
[104] Community and Environmental Parties Joint Proposed Statement of Reasons, New Mexico Environmental Improvement Board rulemaking in the Matter of Proposed New Regulation, 20.2.50 NMAC, Oil and Gas Sector, Ozone Precursor Pollutants (Jan. 20, 2022), *available at* https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/2022-01-20-EIB-No.-21-27-Comty.-and-Envt.-Parties-Proposed-Statement-of-Reasons-pj.pdf.

D. Abandoned and Idle Wells

1. EPA's Proposal

EPA is proposing to include idle wells in LDAR inspections and is proposing specific inspection and other requirements prior to permanent well closure activities. Specifically, operators of idle wells must conduct LDAR inspections "when the wells at the site are shut-in or idled and could be put back into production at a later date."[105] Monitoring must continue until "the well site has been properly closed" and "the OGI survey indicates no emissions are present."[106] If any emissions are identified, the owner or operator would be required to take steps to eliminate those emissions and resurvey prior to well closure. The EPA is proposing that once the OGI survey indicates no emissions are present, the well site would be considered closed and no further fugitive emissions monitoring would be required.

EPA also proposed that operators must develop and submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility. The plan would include: (1) the steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. EPA is also proposing to require owners and operators to report, through the annual report, any changes in ownership at individual well sites so that it is clear who is responsible until the site is plugged and closed.

2. LGC Recommendations

We appreciate EPA's acknowledgement that emissions from idle wells are, in some cases, "very large,"[107] and EPA's proposal for monitoring until no emissions are detected by OGI. In Colorado operators must continue to conduct LDAR inspections at shut-in wells provided such wells remain under pressure.[108] In addition, Colorado requires operators conduct Bradenhead monitoring and testing on a monthly basis for wells an operator intends to plug and abandon, as indicated by inclusion on an operator's out-of-service list, until the operator plugs and abandons the well.[109] Operators must also conduct an AVO or other inspection of each out of service well annually to confirm integrity of the wellhead.[110] New Mexico requires annual Method 21 or OGI inspections at idle wells, beginning 30 days after a well is placed into idle status.[111]

We also support the requirement that an operator submit a well closure plan. However, we recommend EPA require operators submit this plan at the beginning of a well's life (specifically within 30 days of receipt of approval to drill a well) rather than at the end of a well's life. This is necessary to ensure that operators have an adequate plan in place to ensure the proper plugging

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[105] 87 Fed. Reg. at 74,736.
[106] *Id.*
[107] 87 Fed. Reg. at 74,736.
[108] Colorado APCD PS Memo 14-04, p.10, (May 16, 2022), *available at* https://cdphe.colorado.gov/air-permitting-guidance-memos.
[109] 2 Colo. Code Regs. § 404-1-434.d.(11).A.
[110] 2 Colo. Code Regs. § 404-1-434.d.(11).D.
[111] N.M. Code R. § 20.2.50.116.C.(3)(g).

and abandonment of all wells. The time when an operator is best positioned to put aside resources to cover the costs of properly plugging, abandoning, and reclaiming any environmental contamination, is during the initial phase of well development. It is then that a well is most productive and the operator has access to a steady revenue stream from hydrocarbon production. Waiting to require a well closure plan until a well is at the end of its life, and thus at the tail end of its productive, revenue-generating life, could lead to the submission of inadequate plans.

We also recommend EPA require operators review, and revise if appropriate, well closure plans for all wells they acquire in an asset transfer transaction. Purchasers should be required to update well closure plans if any circumstances covered by the well closure plan have changed. Specifically, purchasers must provide EPA with an updated well closure plan if any of the following has changed since the original submission of the well closure plan: the steps necessary to close all wells at the well site, including plugging of all wells; the financial requirements and disclosure of financial assurance to complete closure; and the schedule for completing all activities in the closure plan. This will ensure well closure plans remain relevant and up to date.

V. Conclusion

We appreciate and support EPA's Proposal to require robust controls to limit VOC and methane emissions from new, modified, and existing oil and gas sources, and look forward to EPA finalizing a strong rule which further reduces harmful pollutants from the oil and gas industry.

Respectfully submitted this 13th day of February, 2023.

On Behalf of City of Aurora

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On Behalf of Town of Erie

David Frank, Energy & Environment Program Specialist, Town of Erie

On Behalf of Colorado Communities for Climate Action

Jacob Smith, Executive Director
Colorado Communities for Climate Action

<u>Exhibit C</u>

Declaration of Michelle Miano, New Mexico Environment Department

ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*, Respondents.	No. 24-1054 (and consolidated cases)

DECLARATION OF MICHELLE MIANO

I, Michelle Miano, declare as follows:

1. I submit this declaration in support of State Respondent-Intervenors' Response to Petitioners' Motion to Stay (ECF No. 2055134) the United States Environmental Protection Agency's final rule entitled, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil & Natural Gas Sector Climate Review," published at 89 Fed. Reg. 16,820 (Mar. 8, 2024) (the "Final Rule").

2. I serve as the Director of the Environmental Protection Division at the New Mexico Environment Department (NMED). My position directly manages and supports the bureaus in my division, which are: the Air Quality Bureau, the Climate Change Bureau, and the Radiation Control Bureau.

3. My position duties include directing and working closely with the Air Quality Bureau and the Climate Change Bureau to develop public health and environmental management policy, regulatory and compliance assurance strategies, directing operational activities, leading collaboration efforts with stakeholders; initiating, reviewing, and drafting legislation; and developing compliance and enforcement strategies.

4. I am familiar with the Final Rule, which establishes 40 C.F.R. Part 60 Subparts OOOOb and OOOOc.

5. New Mexico is home to a large and growing oil and gas industry. New Mexico is currently the number two onshore oil and gas producer in the United States, accounting for roughly more than fourteen percent (14%) of United States oil production, and the number six onshore natural gas producer, accounting for roughly seven and one half percent (7.5%) of United States natural gas production.[1] In 2022, New Mexico operators produced 588,064,720 barrels of oil and 2,709,396,300 MCF[2] of gas.[3] In 2023, those numbers rose to 665,029,373 barrels of oil and 3,121,283,895 MCF of gas.[4]

6. The Permian basin, which straddles the New Mexico-Texas state line, is the most prolific crude oil production region in the United States. According to publicly available state-specific data compiled by the New Mexico Energy, Minerals and Natural Resources Department (EMNRD), Oil Conservation Division (OCD), New Mexico contains over 51,434 active oil and gas wells, of which 34,231 are marginal wells (less than 15 barrels per day). According to OCD, New

[1] https://www.eia.gov/state/?sid=NM

[2] MCF is an industry standard unit of measure to report natural gas production. MCF refers to the volume of 1,000 cubic fee of gas. https://www.eia.gov/tools/faqs/faq.php?id=45&t=8.

[3] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx

[4] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx

Mexico crude oil production increased from approximately 146 million barrels in 2016 to over 665 million barrels in 2023[5], while New Mexico gas production increased from approximately 1.2 billion MCF in 2016 to over 3.1 billion MCF in 2023.[6]

7. In 2021 and 2022, New Mexico implemented two key regulatory initiatives to curb the release of methane and ozone precursors.

8. Specifically, in 2021 OCD promulgated Title 19, Chapter 15, Part 27 "Venting and Flaring of Natural Gas"[7]and Part 28 "Natural Gas Gathering Systems" in 2021 to reduce methane emissions and prevent waste of natural gas. These state waste prevention regulations prohibit routine venting or flaring and provide for a phased approach to require capture of at least 98% of gas produced by end of 2026.[8] At Phase 1, operators must collect and report data to identify the sources of emissions (from wellhead to processing and beyond) and then benchmarks are set for each operator.[9] At Phase 2, operators must show increasing progress until they reach the 98% capture threshold.[10] In addition, vented and flared gas are considered waste and subject to payment to the state of royalties and taxes.[11] OCD is currently in Phase 2 of implementation.

9. In 2022, NMED promulgated Title 20, Chapter 2, Part 50 "Oil and Gas Sector – Ozone Precursor Pollutants", which focuses on reducing emissions of volatile organic compounds and nitrogen oxides from the oil and gas sector. The

[5] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx.
[6] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx

[7] 19.15.28 NMAC
[8] *Id.*
[9] *Id.*
[10] *Id.*
[11] *Id.*

regulations require at least annual optical gas imaging ("OGI") inspections of all well sites for leaks, including wellhead only well sites. N.M. Code R. § 20.2.50.116. New Mexico's recently proposed regulations apply OGI leak detection requirements to all wells with no exceptions, with every well in the state to receive leak inspections at least once a year, and larger, potentially higher emitting wells receiving semiannual or quarterly inspections.[12]

10. New Mexico's rules are informative, and EPA utilized these rules to inform its own Final Rule.

11. In 2020, prior to the rules, New Mexico oil and gas totals were 375,830,205 barrels of oil and 1,966,206,785 MCF of gas or approximately 1.0 million barrels per day of oil and 5.3 million MCF per day of gas.[13] In 2023 those numbers have increased to 665,029,373 barrels oil and 3,121,283,895 MCF gas or approximately 1.8 million barrels per day of oil and 8.6 million MCF per day of gas.[14] This shows continued substantial growth of the industry under the new state regulations.

12. To date, based on publicly available data maintained by OCD, approximately 91% of operators are reporting as required under the state waste rule. Those operators represent more than 99%[15] of the all the gas produced in the state. Based on that reporting, industry is currently capturing 99.15% of its

[12] *See* New Mexico Environment Department, Proposed 20.2.50 NMAC (Jan. 20, 2022 version), at 20.2.50.16 *available at* https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

[13] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx

[14] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/Production/ProductionInjectionSummaryReport.aspx

[15] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/NaturalGasWaste/UpstreamNaturalGasWasteSummaryReport.aspx

produced gas in 2022 and 98.91%[16] of its produced gas in 2023, all increases relative to pre-rule capture rates.

13. Since the implementation of New Mexico's rules, neither NMED nor OCD have seen a significant increase in the number of operator bankruptcies, an increase in the number of inactive wells, or a decline in the number of permits being submitted.

14. Although New Mexico has its own state regulatory scheme, the Final Rule is fundamental to reducing emissions from the oil and natural gas sector not only in New Mexico, but throughout region.

15. For example, as New Mexico is working to decrease its emissions, Texas operators face less stringent requirements and are routinely allowed to flare excess emissions.[17] Therefore, strong, federally enforceable standards for new and existing oil and gas sources are necessary to ensure that fair and equitable requirements span state lines.

16. Further, any delay in the Final Rule taking effect will make it more difficult for New Mexico to keep certain of its counties in attainment. Exceeding ozone standards results in a nonattainment status designation, which leads to expensive requirements for communities and the State of New Mexico. Nonattainment areas require air quality permits to include the lowest achievable emission rate technology and permit emission offsets for any new or modified operations. Offsets are emission reductions, generally obtained from existing sources located in the vicinity of a proposed source, that must (1) offset the

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[16] https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Reporting/NaturalGasWaste/UpstreamNaturalGasWasteSummaryReport.aspx

[17] See https://www.reuters.com/markets/commodities/texas-operators-turn-flaring-amid-weak-gas-prices-2024-04-30/

emissions increase from a new source or modification and (2) provide a net air quality benefit.

17. A nonattainment designation under section 107(d) of the Clean Air Act carries potentially serious sanctions and damaging repercussions for an area, including the potential loss of federal highway funding and economic development opportunities.

I declare under penalty of perjury that the foregoing is true and correct to the best of my ability.

Executed on: June 11, 2024

Signature:

Michelle Miano
Director, Environmental Protection Division
New Mexico Environment Department